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**BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) AUGUST 8, 2016 DRAFT RENEWABLE ENERGY PROCUREMENT PLAN

(PUBLIC VERSION)

[Redactions in Plan and Appendices A, B, C, D, F, G, H, J]

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Dated: August 8, 2016

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In compliance with the *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans*, issued on May 17, 2016 ("Ruling"), Pacific Gas and Electric Company ("PG&E") hereby files its 2016 Draft Renewable Energy Procurement Plan (the "2016 RPS Plan"). Consistent with the Ruling, PG&E has included in its filing both clean and redlined versions of the 2016 RPS Plan, with the redline showing changes from the Final 2015 RPS Plan wherever applicable.

In addition, PG&E recognizes that the 2016 RPS Plan includes many acronyms that are used throughout the document. To assist parties in reviewing the 2016 RPS Plan, PG&E has prepared the following list of acronyms used in the document:

2016 RPS Plans
Acronym List

Acronym	Term
2016 RPS Plan	2016 Draft Renewable Energy Procurement Plan
AB	Assembly Bill
ACR	Assigned Commissioner's Ruling

Acronym	Term
ALJ	Administrative Law Judge
BioMAT	Bioenergy Market Adjusting Tariff
BioRAM	Bioenergy Renewable Auction Mechanism
BPP	Bundled Procurement Plan
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
D.	Decision
DA	Direct Access
DG	Distributed Generation
DLAP	Default Load Aggregation Point
ECR	Enhanced Community Renewables
EE	Energy Efficiency
EO	Energy Only
ERR	Eligible Renewable Resource
ESP	Energy Service Provider
FIT	Feed-In Tariff
GHG	Greenhouse Gas
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
GRC	General Rate Case
GTSR	Green Tariff Shared Renewables
GWh	Gigawatt-Hour
HHZ	High Hazard Zone
ID&WA	Irrigation Districts and Water Agencies
IOU	Investor-Owned Utility
ITC	Investment Tax Credit
kWh	Kilowatt-Hour

Acronym	Term
LCBF	Least-Cost Best-Fit
LSE	Load-Serving Entity
LTPP	Long-Term Procurement Plan
MACRS	Modified Accelerated Cost Recovery System
MVI	Motor Vehicle Incident
MW	Megawatt
NBC	Non-Bypassable Charge
NMV	Net Market Value
NP15 Hub	North of Path 15 Hub
NPV	Net Present Value
OSHA	Occupational Safety and Health Administration
PAV	Portfolio Adjusted Value
PCC	Portfolio Content Category
PEL	Procurement Expenditure Limitation
PG&E	Pacific Gas and Electric Company
PPA	Power Purchase Agreement
PQR	Portfolio Quantity Requirements
PRG	Procurement Review Group
PTC	Production Tax Credit
PTO	Participating Transmission Owner
PV	Photovoltaic
QF	Qualifying Facility
R.	Rulemaking
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
RETI	Renewable Energy Transmission Initiative
RFO	Request for Offer
RNS	Renewable Net Short
RPS	Renewables Portfolio Standard

Acronym	Term
RTM	Real-Time Markets
Ruling	*Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans* issued May 17, 2016
SANS	Stochastically-Adjusted Net Short
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SONS	Stochastically-Optimized Net Short
SRAC	Short Run Avoided Cost
TOD	Time of Delivery
TPP	Transmission Planning Process
UOG	Utility-Owned Generation
VMOP	Voluntary Margin of Procurement

Respectfully submitted,

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By: */s/ Charles R. Middlekauff*
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PACIFIC GAS AND ELECTRIC COMPANY

Dated: August 8, 2016

<u>VERIFICATION</u>

I, Brendan Lucker, am an employee of Pacific Gas and Electric Company, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing:

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
AUGUST 8, 2016 DRAFT RENEWABLE ENERGY PROCUREMENT PLAN
(PUBLIC VERSION)

The statements in the foregoing document are true to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 28th day of July, 2016 at San Francisco, California.

<u>/s/ Brendan Lucker</u>
BRENDAN LUCKER
Manager, Renewable Energy Strategy
Pacific Gas and Electric Company

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

DRAFT 2016 RENEWABLE ENERGY PROCUREMENT PLAN

AUGUST 8, 2016

PUBLIC VERSION

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Pacific Gas and Electric Company ("PG&E") respectfully submits its Draft 2016 Renewables Portfolio Standard ("RPS") Plan ("2016 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed in the *Assigned Commissioner and Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans* issued on May 17, 2016 ("Ruling").[1] PG&E's 2016 RPS Plan includes a summary of key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the Ruling.[2]

1. Summary of Key Issues

1.1. PG&E's RPS Position

PG&E projects that under the 33% RPS by 2020 target, and an assumed "straight-line" trajectory implementing the Senate Bill ("SB") 350 target of 50% RPS by 2030, it is well-positioned to meet its RPS compliance requirements for the second (2014-2016), third (2017-2020), and fourth (2021-2024) compliance periods and will not have incremental RPS physical need until at least 2026.[3] PG&E projects that it will have incremental RPS procurement need beginning in [redacted], after applying banked volumes of excess procurement ("Bank") beginning in [redacted]. Changes to PG&E's

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1 Administrative Law Judge ("ALJ") Mason sent an email on June 8, 2016 allowing Investor-Owned Utilities ("IOU"), Small Utilities, Energy Service Providers and Community Choice Aggregators ("CCA") until August 8, 2016 to file proposed annual RPS Procurement Plans.

2 *See* Ruling, pp. 3-20.

3 PG&E announced in June that it had entered into a Joint Proposal with a number of parties for the orderly retirement of the Diablo Canyon Power Plant and its replacement with greenhouse gas ("GHG")-free resources, possibly including RPS resources procured through an all-source Request for Offer ("RFO") framework and a voluntary 55% RPS commitment. PG&E intends to file an application requesting Commission approval of specific elements of the Joint Proposal, including elements related to GHG-free resource procurement. However, because the Commission has not yet reviewed and approved the Joint Proposal, the GHG-free resource elements of the Joint Proposal are not included in this draft of the 2016 RPS Plan.

near-term RPS position and increases in PG&E's forecasted surplus RPS volume have been driven primarily by declining retail sales projections.

Given its forecasted position, PG&E has developed a framework to assess whether to hold or sell excess RPS volumes. The proposed framework is summarized in Sections 1.4 and 19 below, and described in more detail in Appendix J. Based on PG&E's current load forecast and RPS position, applying the proposed framework would lead PG&E to hold one or more solicitations for sales of surplus bankable, bundled RPS volumes in 2017. PG&E anticipates additional steady, incremental sales or procurement in subsequent years to manage its RPS position and maintain adequate minimum Bank levels. Should PG&E engage in RPS sales, its position will be updated in subsequent RPS Plans to reflect an earlier procurement need year.

1.2. PG&E Proposes Not to Hold a Solicitation to Procure in 2016

Given its current RPS compliance position, PG&E is proposing in this 2016 RPS Plan not to hold an RPS procurement solicitation for the 2016 solicitation cycle. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for procurement solicitations in future RPS Plans. Although many factors could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, even without an RPS solicitation, PG&E expects to continue to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs in 2017.[4] PG&E will seek permission from the Commission to procure any amounts other than amounts separately mandated by the Commission during the time period covered by the 2016 solicitation cycle.

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4 Mandated programs include Renewable Market Adjusting Tariff ("ReMAT"), Bioenergy Renewable Auction Mechanism ("BioRAM"), and Bioenergy Market Adjusting Tariff ("BioMAT"). In addition, while not pursuant to the RPS mandate, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program.

PG&E does not support expansion of existing mandated programs or additional new mandated programs.[5] Mandated procurement programs do not optimize costs for customers because they restrict flexibility and optionality to achieve the RPS targets by mandating procurement through a potentially less efficient and more costly manner. PG&E supports a technology-neutral procurement process, in which all RPS-eligible technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

PG&E will continue to annually reassess its Renewable Net Short ("RNS") position and determine its updated procurement needs. PG&E's proposal not to hold a 2016 RPS procurement solicitation is consistent with past proposals to not hold RPS solicitations made by PG&E and San Diego Gas & Electric Company ("SDG&E") in their respective 2015 RPS Plans, which were approved by the Commission given lack of RPS need.[6]

1.3. Maintaining Some Level of Bank Is Necessary to Ensure PG&E's Long-Term Compliance and Customer Affordability

PG&E views having a minimum Bank as necessary to: (1) mitigate risks associated with uncertainty in load; (2) protect against project failure or delay exceeding forecasts; and (3) manage year-to-year generation variability from RPS resources. The Bank allows PG&E to mitigate the need to procure additional RPS products at potentially high market prices in order to meet near-term compliance deadlines. More information on forecasted Bank size and minimum Bank levels is provided in Section 7 below.

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5 PG&E also notes that on January 22, 2016, it filed a Petition to Modify D.14-11-042 to eliminate the requirement that PG&E conduct solicitations in 2016 and 2017 for additional photovoltaic ("PV") resources resulting from PG&E's closed PV Program. The petition for modification is still pending at the Commission.

6 D.15-12-025, pp. 35, 62, Ordering Paragraphs 8, 9.

1.4. PG&E Proposes a Framework to Assess Potential Sales of Excess RPS Volumes

PG&E's forecasted RPS position predicts a higher cumulative Bank than its calculated minimum Bank. While the Bank holds value as an instrument for future RPS compliance, PG&E has developed a framework to assess whether to hold or sell excess RPS volumes, which will allow PG&E to rebalance its RPS portfolio to better align its RPS position with its RPS need. PG&E is requesting Commission review and approval of this framework as a part of the 2016 RPS Plan. If approved, the proposed framework will be used to determine future sales of bankable RPS volumes. The details of PG&E's sales framework are discussed in Section 19 and Appendix J. Based on the existing inputs to this framework, PG&E expects to conduct one or more solicitations in 2017 for short-term sales of bundled RPS volumes. PG&E anticipates selling short-term products in 2017, and may consider longer-term offers in the future.

1.5. Any Additional Procurement Due to the Governor's Emergency Proclamation on Tree Mortality Should Be Based on a Clear Demonstration of Need

PG&E remains committed to working closely with the Commission and the state to identify policy solutions and uses for biomass material that is the result of the drought and bark beetle-related tree mortality. While PG&E has been partnering with the state to respond to Governor Brown's Emergency Proclamation on Tree Mortality ("Emergency Proclamation"),[7] PG&E does not have a need to procure RPS resources to meet our customers' needs, and strongly believes that any BioRAM procurement costs must be recovered from all benefitting customers.

Any mandated Emergency Proclamation-related procurement should first be based on a clear demonstration of need. Outside of BioRAM, PG&E is the only IOU currently procuring biomass in the state. If additional Emergency Proclamation-related procurement is found necessary, all load-serving entities ("LSE") must either be

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7 Governor Brown issued the Emergency Proclamation on October 30, 2015 to address the significant drought-related tree mortality concerns in California.

required to participate or costs must be allocated to all benefitting customers in California on a fully non-bypassable basis.[8] Finally, in order to address the statewide emergency, PG&E believes that any additional Emergency Proclamation-related procurement should be of short-term duration and require the use of high-hazard fuel.

2. Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

PG&E's portfolio forecast and procurement decisions are influenced by ongoing legislative and regulatory changes to the RPS Program. The following section summarizes recent legislative and regulatory developments that may impact PG&E's RPS Program. Specifically, this section addresses: (1) the adoption and implementation of SB 350; (2) implementation of bioenergy legislation and directives; and (3) outstanding cost containment issues.

2.1. Adoption and Implementation of Senate Bill 350

On October 7, 2015, Governor Brown signed SB 350, known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increases the RPS target from 33% in 2020 to 50% in 2030. On April 15, 2016, ALJ Simon issued a ruling to begin implementation of SB 350 provisions relating to RPS procurement, including establishing post-2020 compliance periods, and changes to the banking provisions and long-term procurement requirements in 2016.[9]

Commission action on SB 350 implementation, as well as other remaining issues identified in R.15-02-020, may impact PG&E's procurement need and actions going forward. PG&E notes that its 2016 RPS Plan reasonably reflects aspects of

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8 PG&E and Southern California Edison Company ("SCE") filed a *Petition For Modification Of Decision 10-12-048* in Rulemaking ("R.") 08-08-009 on April 19, 2016 regarding the allocation of costs related to the Emergency Proclamation. This petition for modification is still pending at the Commission.

9 *Administrative Law Judge's Ruling Requesting Comments on Implementation of Elements of Senate Bill 350 Relating to Procurement under the California Renewables Portfolio Standard*, issued April 15, 2016.

SB 350, including a “straight-line” RPS target trajectory from 33% to 50%. However, these assumptions should be treated as preliminary as the Commission has not yet issued a final decision(s) on SB 350 implementation.

One specific aspect of SB 350 requires some additional discussion. SB 350 added a 65% long-term contracting requirement in California Public Utilities Code (“Pub. Util. Code”) Section 399.13(b).[10] The Commission has not yet adopted implementation rules regarding this requirement. However, Section 399.13(a)(4)(B)(iii) provides that that “[i]f a retail seller notifies the commission that it will comply with the [minimum long-term requirement] for the compliance period beginning January 1, 2017, the [new RPS banking rules set forth in the same subdivision] shall take effect for that retail seller for that compliance period.” Although the Commission has not yet implemented this new statutory language by specifying the manner or process by which a retail seller must notify the Commission of its intent to comply early with the minimum long-term requirements, PG&E intends this 2016 RPS Plan to provide such notice if the Commission ultimately determines that the notice should be provided as part of the annual RPS Plan submissions.

PG&E will revisit these assumptions in future RPS Plans once the Commission provides final guidance on the manner or process for which a retail seller is to provide notice of its intent to comply early with the minimum long-term contract provisions to the Commission.

2.2. Implementation of Bioenergy Legislation and Directives

The Emergency Proclamation, which was described above in Section 1.5, is targeted at multiple state agencies to identify High Hazard Zones (HHZ) and facilitate wildfire mitigation across the state. The Emergency Proclamation specifically identifies actions for the Commission, such as expediting new contract execution through BioMAT or a new targeted procurement mechanism. The Commission has responded by

10 All further statutory references are to the California Pub. Util. Code unless otherwise noted.

considering changes to the BioMAT program, as well as initiating a new procurement program for bioenergy facilities. PG&E briefly describes these developments below.

2.2.1. BioMAT

On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure 250 megawatts ("MW") in total of new small-scale bioenergy projects 3 MW or less through the Feed-In Tariff ("FIT") Program. The total IOU program MWs are allocated into three technology categories: 110 MW for biogas from wastewater plants and green waste; 90 MW for dairy and other agriculture bioenergy; and 50 MW for forest waste biomass. On December 18, 2014, the Commission issued Decision ("D.") 14-12-081 to implement SB 1122 and required the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015, which were approved with modifications in D.15-09-004. PG&E's SB 1122 Program (BioMAT) began accepting participants on December 1, 2015 and the first program period (auction) was held on February 1, 2016. The second program period (auction) was held on April 1, 2016. The Commission is currently considering changes to the BioMAT Program, including higher contract prices for facilities that use forest fuel from HHZs, fuel verification requirements and clarification of the existing BioMAT interconnection requirements.

2.2.2. BioRAM

To further address the Emergency Proclamation, the Commission initiated a new procurement program for bioenergy facilities (BioRAM) which requires the IOUs to procure energy from bioenergy facilities using forest fuel supplied from wildfire HHZs. Facilities participating in BioRAM are required to meet annual minimum levels of fuel source from HHZs, starting at 40% in 2016 and increasing to 80% in 2020 and beyond. BioRAM has a minimum program size of 50 MW; PG&E's share is a minimum of 20 MW. Before beginning the program, the IOUs were required to modify their existing

Renewable Auction Mechanism ("RAM") contract language in order to specifically address the BioRAM considerations.[11] PG&E launched the BioRAM solicitation on June 28, 2016 with offers due on July 28, 2016. More details related to PG&E's biomass portfolio and its response to the Emergency Proclamation is discussed in Section 18 of the 2016 RPS Plan.

On April 19, 2016, PG&E and SCE filed a joint Petition for Modification of D.10-12-048, which authorized the RAM Program, to specify that any contract-related costs incurred as part of the implementation of the Emergency Proclamation be allocated to all benefitting parties (*i.e.*, bundled, CCA, and Direct Access ("DA") customers) using a new Non-Bypassable Charge (a "BioRAM NBC") or, alternatively, the Cost Allocation Mechanism. The Petition for Modification is still pending at the Commission.

2.3. Cost Containment

When California's legislature passed SB 2 (1x), it required the Commission to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS target from causing "disproportionate rate impacts." SB 350 modified certain criteria regarding cost containment, including allowing for the consideration of indirect costs in setting the cost cap.[12] If PG&E exceeds the Commission-approved cost cap, it may refrain from entering into new RPS contracts and constructing RPS-eligible facilities unless additional procurement can be undertaken with only "de minimis" rate impacts.

PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can

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11 On April 7, 2016, PG&E and the other IOUs filed advice letters with the Commission with their proposed contract modifications and on June 1 and June 3, PG&E filed two supplemental advice letters with an updated contract and solicitation protocol. The Commission issued a Disposition Letter approving PG&E's advice letter and supplemental advice letters on June 14, 2016.

12 Cal. Pub. Util. Code §399.15(c).

have on customers, PG&E strongly supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation ("PEL") that both informs procurement planning and decisions, and promotes regulatory and market certainty. Implementation of the PEL has been ongoing at the Commission since SB 2 (1X) was passed five years ago. During that time, the Commission and stakeholders have taken actions related to developing a cost containment proposal, including holding a workshop in November 2013 to discuss Energy Division staff's PEL proposal, alternate proposals, and implementation details, as well as issuing and seeking comments on a revised proposal in February 2014. PG&E urges the Commission to finalize the PEL as soon as possible.

3. Assessment of RPS Portfolio Supplies and Demand

3.1. Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's 50% RPS target. PG&E is currently required to procure the following quantities of RPS-eligible products:

- 2011-2013 (First Compliance Period): 20% of the combined bundled retail sales.
- 2014-2016 (Second Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).

- 2021-2024: 40% of combined bundled retail sales by end of period.[13]
- 2025-2027: 45% of combined bundled retail sales by end of period.
- 2028-2030: 50% by end of period and each year thereafter.

Based on preliminary results presented in Appendix C.2, PG&E delivered 29.5% of its power from RPS-eligible renewable sources in 2015.

As described more fully in Section 7 and reported in the current RNS calculations in Appendix C.2, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements for the second (2014-2016), third (2017-2020), and fourth (2021-2024) compliance periods. Under the 50% RPS by 2030 target, PG&E projects that it will not have incremental RPS physical need until at least 2026, and a procurement need beginning in [redacted] after applying the Bank beginning in [redacted]. Should PG&E engage in RPS sales, its position will be updated in subsequent RPS Plans to reflect an earlier procurement need year.

3.2. Supply

3.2.1. Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes approximately 8,000 MW of active projects, ranging from utility-owned solar and small hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass to small FIT contracts for solar PV, biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 6 and 7.

As described in further detail in Section 7.1, for the 2016 RPS Plan, PG&E assumes a volumetric expected success rate for all executed in-development projects in

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13 For SB 350 compliance periods, PG&E is assuming a "straight line" compliance pathway between the end of compliance period targets established in SB 350, as this is consistent with the current assumptions for how the target is calculated.

its RPS portfolio of 100% of total contracted volumes.[14] This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations.

Consistent with the project trends reported in its 2015 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have continued to increase many projects' cost-effectiveness, contributing to their eventual completion. Progress in the siting and permitting of projects has also supported PG&E's sustained high success rate. As described in more detail in this section, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in the remainder of Section 3 and Section 4.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 4, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted.

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14 PG&E's success rate discussed is more reflective of the success rate of its overall portfolio, and so this percentage does not convey that PG&E has no projects failing. Specifically, since almost all of PG&E's in-development projects are volumes procured through mandated programs with set targets, any projects that fail will be replaced through future solicitation rounds. Therefore, the effect on PG&E's portfolio is that the amount of volumes projected has a very high project success rate, given that any failed project will be replaced with a new project, until the volumes come online.

3.2.2. Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program that allows PG&E customers to meet up to 100% of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission issued D.15-01-051 implementing a GTSR framework, approving the IOUs' applications with modifications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment.

Pursuant to D.15-01-051, PG&E submitted several advice letters related to implementation of the GTSR Program. In February 2015, PG&E filed an advice letter containing its plans for advance procurement for the GTSR Program and identifying the eligible census tracts for environmental justice projects in its service territories.[15] In May 2015, together with SCE and SDG&E, PG&E submitted a Joint Procurement Implementation Advice Letter, addressing each utility's plans for ongoing GTSR Program procurement and RPS resource and Renewable Energy Credit ("REC") separation and tracking.[16] The Joint Procurement Implementation Advice Letter and supplemental filing became effective on November 20, 2015.

Concurrent with the Joint Procurement Implementation Advice Letter, PG&E filed a Marketing Implementation Advice Letter[17] and a Customer-Side Implementation Advice Letter[18] with details regarding implementation. The Marketing Implementation Advice Letter and supplemental filing became effective on October 1, 2015 and the Customer-Side Advice Letter and supplemental filing became effective on November 20, 2015.

In addition, to accommodate GTSR procurement, PG&E filed Advice Letter 4605-E to change its RAM 6 Power Purchase Agreements ("PPA") and RFO

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15 PG&E Advice Letter 4593-E (supplemented March 25, 2015).

16 Advice Letter 4637-E.

17 Advice Letter 4638-E.

18 Advice Letter 4639-E.

instructions, consistent with the minimum goals for 2015 identified in D.15-01-051.[19] Advice Letter 4605-E was approved via a Disposition Letter dated June 17, 2015.

On July 7, 2015, PG&E launched its RAM 6 solicitation seeking 50 MW for the GTSR Program. In December and January 2016, PG&E executed eight GTSR Program PPAs for a total of 52.75 MW, which were filed for approval as part of Advice Letter 4780-E on January 22, 2016. The facilities pursuant to these PPAs are currently under development and their status is included in the Project Development Status Update section (see Chapter 4).

TABLE 3-1
PROGRESS OF GTSR PROGRAM PROCUREMENT

Procured Capacity (as of May 2016)	Available Capacity (MW)	GT Procured (MW)	ECR Procured (MW)	Remaining Capacity (MW)
Unrestricted Other Community	207	50.75 44.50 6.25	0	156.25
EJ Reservation	45	2	0	43
City of Davis	20	0	0	20
Totals	**272**	**52.75**	**0**	**219.25**

In January 2016, PG&E's GTSR Program opened for enrollment under the program name "PG&E's Solar Choice." On March 15, 2016, PG&E filed its 2015 Green Tariff Shared Renewables Annual Report with the Commission.

On May 19, 2016, the Commission issued D.16-05-006 regarding Phase IV issues in the GTSR proceeding. This decision addressed participation of Enhanced Community Renewables ("ECR") projects in RAM solicitations and made refinements to the GTSR Program. Later this year, PG&E will hold its first ECR RFO using the RAM solicitation, pursuant to D.16-05-006.

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19 *See* D.15-01-051, Section 4.2.4, pp. 25-28.

The GTSR Program impacts PG&E's RPS position in two ways: (1) RPS supply may be affected; and (2) retail sales will be reduced corresponding to program participation. D.15-01-051 permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. In this case, those volumes procured for GTSR would then be added to PG&E's RPS portfolio, even if PG&E had no RPS need. PG&E is developing tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff Programs.

In conformance with D.15-01-051[20] and as described in the Joint Procurement Implementation Advice Letter, PG&E will report annually on the amount of generation transferred between the RPS and GTSR Programs in a report to be filed on September 1 following the launch of each IOU's GTSR Program. PG&E will file its first Annual GTSR Tracking Report on September 1, 2017, to report generation transfers between the RPS and GTSR Programs. For purposes of this 2016 RPS Plan, PG&E updated the RNS calculations to reflect expected GTSR Program impacts on retail sales and RPS supply.

3.2.3. RPS Market Trends and Lessons Learned

As its renewable portfolio has expanded to meet the RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the four key goals of: (1) reaching, and sustaining, the 50% RPS target; (2) minimizing customer cost within an acceptable level of risk; (3) ensuring it maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty; and (4) aligning PG&E's RPS portfolio to its customers' needs. PG&E is continually

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20 *See* D.15-01-051, p. 50.

adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as solar PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

Another trend, driven by the growth of renewable resources in the California Independent System Operator ("CAISO") system, is the downward movement of mid-day market prices. Many renewable energy project types have little to no variable costs and therefore additions tend to move market clearing prices down the dispatch stack. This has led to a change in the energy values associated with RPS offers, with decreasing value of renewable projects that generate during mid-day hours.

The growth of renewable resources has also produced operational challenges, such as overgeneration situations and negative market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address overgeneration and negative pricing situations that are likely to increase in frequency in the future. These provisions have both operational and customer benefits. From an operational perspective, this flexibility allows PG&E to offer its RPS-eligible resources into the CAISO's economic dispatch, which can reduce the potential for overgeneration conditions and facilitate reliable operation of the electrical grid. In addition, economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 11.

3.3. Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Compliance rules for the RPS Program were established in D.12-06-038. In addition, the Commission issued D.11-12-052, to define three statutory portfolio content categories of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 4; in particular, uncertainty around bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

3.3.1. Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need through [redacted] under a 50% RPS requirement, PG&E is proposing not to hold an RPS solicitation for the 2016 solicitation cycle. As discussed in the summary of key issues, PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future RFOs in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to continue procurement of additional volumes of incremental RPS-eligible contracts in 2017 through mandated procurement programs, such as the ReMAT, BioRAM, and BioMAT Programs. PG&E will seek permission from the Commission should PG&E intend to procure any amounts other than amounts separately mandated by the Commission (*i.e.*, FIT and BioRAM) during the time period covered by the 2016 RPS Plan.

3.3.2. Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. PG&E is currently projecting a decrease in retail sales in 2016 and a continued retail sales decrease through 2028, followed by modest growth thereafter. These changes are driven by the increasing impacts of Energy Efficiency (EE), customer-sited generation, and DA and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 6, 7 and 8, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement; and (2) the need to account for its risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 6 and 7.

3.4. Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs such as the ReMAT, BioRAM, and BioMAT Programs, PG&E does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost. Starting in the 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio. When this adder is finalized by the Commission, PG&E's Net Market Value ("NMV") methodology will be updated to use the values and methodologies of the final integration cost adder. PG&E's PAV and NMV methodologies were described in detail in PG&E's 2014 RPS Solicitation Protocol.[21]

3.5. RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including solar PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the NMV valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in procurement of different technology types.

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic

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21 *See* PG&E, 2014 RPS Solicitation Protocol, pp. 24-28 (available at http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/RPS_Solicitation_Protocol_01052015.pdf).

concentration. In general, PG&E believes that less restrictive procurement structures provide the best opportunity to maximize value for its customers, allowing proper response to changing market conditions and more competition between resources, while geographic or technology-specific mandates add additional costs to RPS procurement.

3.6. Optimizing Cost, Value, and Risk for the Ratepayer

From 2003-2012, PG&E's annual RPS-eligible procurement and generation costs from its existing contracts and utility-owned portfolio grew at a relatively modest pace. However, the costs of the RPS Program are becoming more apparent on customer bills and will increase as RPS projects come online in significant quantities. Over the period of 2013 and 2014, the renewable generation in PG&E's portfolio increased by approximately the same amount that it grew over the entire prior history of the RPS Program (2003-2012). During 2015, PG&E's renewable generation costs continued to increase. In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

PG&E is aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement; and (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline, and using the Bank to mitigate risks associated load uncertainty, project failure, and generation variability. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 14.2, the cost impacts of mandated procurement programs that focus on particular technologies or project size may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process, in which all technologies can compete to offer the best value to customers at the lowest cost.

3.7. Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond 2030 and to minimize customer cost within an acceptable level of risk. Although PG&E remains mindful of meeting near-term compliance targets, it also seeks to refine strategies for maintaining compliance in a least-cost manner in the long-term (post-2030). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to manage a 50% RPS operating portfolio after 2030. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 6 and 7.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement (if needed); (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E is proposing not to hold a 2016 RPS procurement solicitation, future incremental procurement to avoid the need to procure extremely large volumes in any single year remains a component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes consideration of sales of surplus procurement that provide a value to customers. PG&E has developed a framework for surplus sales, which is described in Appendix J, and is requesting Commission approval of the proposed framework in this proceeding.

The third component of the optimization strategy is effective use of the Bank. Under the existing 50% RPS target and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in [redacted]. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted]. See Section 7 for additional information regarding the use and size of PG&E's Bank.

4. Project Development Status Update

In Appendix B, PG&E provides an update on the development of RPS-eligible resources currently under contract but not yet delivering energy. The table in Appendix B updates key project development status indicators provided by counterparties and is current as of June 1, 2016.[22] These key project development status indicators help PG&E to determine if a project will meet its contractual milestones and identify impacts on PG&E's renewable procurement position and procurement decisions. Appendix B includes in-development GTSR dedicated contracts that—though RPS eligible—are not counted towards PG&E's RPS position, as explained in Section 3.2.2 and Appendix G.

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22 Appendix B includes PPAs procured through the GTSR Program, RAM, and PV Programs, but does not include small renewable FIT PPAs. PG&E currently has 69 executed Assembly Bill ("AB") 1969 PPAs in its portfolio and 31 ReMAT PPAs, totaling 101.1125 MW of capacity. These small renewable FIT projects are in various stages of development, with 68 already delivering to PG&E under an AB 1969 PPA and 14 delivering to PG&E under a ReMAT PPA. Information on these programs is available at http://www.pge.com/feedintariffs/.

Within PG&E's active portfolio,[23] there are 117 RPS-eligible projects that were executed after 2002. Eighty-three of these contracts have achieved full commercial operation and started the delivery term under their PPAs. Thirty-four contracts have not started the delivery term under their PPAs. Of the 34 contracts that have not started the delivery term under their PPAs with PG&E: 26 have not yet started construction; three have started construction, but are not yet online; four are delivering energy, but have not yet started the delivery term under their PPAs, and one contract is delivering energy under its current RPS contract expiring in 2016 and will be starting the delivery term under a new RPS contract thereafter.

In addition, 8 of the 117 total RPS-eligible projects are designated for the GTSR Program. All eight projects have not currently started construction and are expected to come online by April 2018. How these GTSR-dedicated projects are accounted for in PG&E's RPS position modeling is discussed in Section 3.2.2 and Appendix G.

5. Potential Compliance Delays

This section addresses: (1) obstacles for renewable project developers; and (2) how PG&E mitigates these risks of compliance delay in its modeling and planning.[24]

5.1. Potential Causes of Compliance Delays as a Result of Obstacles to Renewable Project Development

Through the considerable experience it has gained over the past decade of RPS procurement, PG&E is familiar with the obstacles confronting renewable energy

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[23] PG&E's active portfolio includes RPS-eligible projects that were executed (but not terminated or expired) and have been approved by the Commission, not including amended post-2002 Qualifying Facility ("QF") contracts, contracts for the sale of bundled renewable energy and green attributes by PG&E to third parties, Utility-Owned Generation ("UOG") projects, or FIT projects.

[24] This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

developers. Significant obstacles include securing project financing, siting and permitting projects, expanding transmission capacity, and interconnecting projects to the grid. At both the federal and state levels, new programs and measures continue to be implemented to address these issues.

5.1.1. Project Financing

The financing environment for solar PV and wind projects continues to be healthy, with access to low-cost capital, a growing number of investors, and a variety of ownership structures for project developers. Wind and solar deals saw an increase in project finance volume in 2015, with further volume growth expected in 2016 as well.[25]

Federal and state incentives such as the PTC and ITC continue to fuel renewable growth in California. In late 2015, Congress extended the ITC for solar energy, the PTC for wind and other renewable resources, and bonus depreciation.[26] For many developers, this event added significant value to their companies. In addition, the lengthy extensions of the tax credits have provided certainty and caused a developer shift towards raising capital and expansion.

The table below shows the value of the ITC for each renewable technology by year. For solar technologies and wind, the expiration date is based on "commencement of construction." For all other renewable technologies, the expiration date is based on when the system is placed in service.[27]

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25 http://www.renewableenergyworld.com/articles/2016/02/renewable-energy-finance-outlook-2016-the-year-of-the-green-dollar.html.

26 On December 18, 2015, President Barack Obama signed into law the Consolidated Appropriations Act, 2016 (Act). *See* I.R.S. Notice 2013-29, 2013-20 I.R.B. 1085, as clarified by I.R.S. Notice 2013-60, 2013-42 I.R.B. 431, as clarified and modified by I.R.S. Notice 2014-46, 2014-35 I.R.B. 520, and as updated by I.R.S. Notice 2015-25, 2015-13 I.R.B.

27 Solar projects will qualify for the 30 percent ITC if construction begins on or before December 31, 2019, even if the projects are not placed in service until after that date. However, the project must be placed in service before January 1, 2024. Projects placed in service on or after that date would qualify for a 10 percent credit.

Renewable Energy Investment Tax Credit[28]								
Technology	**12/31/16**	**12/31/17**	**12/31/18**	**12/31/19**	**12/31/20**	**12/31/21**	**12/31/22**	**Future Years**
PV, Solar Water Heating, Solar Space Heating/Cooling, Solar Process Heat	30%	30%	30%	30%	26%	22%	10%	10%
Hybrid Solar Lighting, Fuel Cells, Small Wind	30%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Heat Pumps, Microturbines, Combine Heat and Power Systems	10%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Electric	10%	10%	10%	10%	10%	10%	10%	10%
Large Wind	30%	24%	18%	12%	N/A	N/A	N/A	N/A

For wind facilities, the PTC was extended for two years and also structured to phase out. The table below shows the value of the PTC for each renewable resource.

28 Per Section 48 of the Internal Revenue Code. The energy ITC is realized in the year that the project is placed in service.

Renewable Energy Production Tax Credit[29]		
Resource	**Tax Credit Amount**	**Period of Credit**
Wind[30]	2.3 cents per kilowatt-hour (kWh) (inflation adjusted) for facility starting construction through December 31, 2019, with a phase-down beginning for wind projects commencing construction after December 31, 2016: • facilities commencing construction in 2017, the PTC amount is reduced by 20%; • facilities commencing construction in 2018, the PTC amount is reduced by 40%; • facilities commencing construction in 2019, the PTC amount is reduced by 60%	10 years
Geothermal Energy Resources, Closed-Loop Biomass	2.3 cents per kWh (inflation adjusted) for facility starting construction through December 31, 2016	10 years
Open-loop biomass, Landfill gas, Municipal solid waste, Qualified hydroelectric Marine & hydrokinetic energy resources	1.2 cents per kWh (inflation adjusted) for facility starting construction through December 31, 2016	10 years

29 Per Section §45 of the Internal Revenue Code.

30 Wind facilities may also claim the 30 percent energy ITC in lieu of the PTC if the facilities begin construction on or before December 31, 2016.

Congress also extended the bonus depreciation through 2019, as follows:

Tax Depreciation	
For Qualified Property Placed in Service:	**Tax Depreciation Allowance**
On or before December 31, 2017	50% Bonus Depreciation, then Modified Accelerated Cost Recovery System (MACRS)[31]
In 2018	40% Bonus Depreciation, then MACRS
In 2019	30% Bonus Depreciation, then MACRS
Beyond 2019	5 and 7 MACRS

The tax incentives and the tax depreciation deductions enable developers and businesses to reduce their tax liability and accelerate the rate of return on renewable investments. They also provide a workable framework for negotiating financing arrangements. As a result, the tax incentives encourage significant investment in renewable energy and generally amount to between 35 and 60 cents per dollar of capital cost.

Tax equity remains a core financing tool for renewable developments and ownership structures such as the partnership flip, Master Limited Partnerships, and Yield Cos continue to be utilized by project sponsors. These structures allow developers who cannot use tax benefits efficiently to barter the benefits to large corporations or investors in exchange for cash infusions for their projects.

PG&E believes the healthy trends for renewable project financing will continue well into the future.

5.1.2. Siting and Permitting

PG&E works with various stakeholder groups toward finding solutions for environmental siting and permitting issues faced by renewable energy development.

31 MACRS provides for a five-year tax cost recovery period for renewable solar, wind, geothermal, fuel cells and combined heat and power tangible property. Certain biomass property is eligible for a seven-year tax cost recovery period under MACRS.

For example, PG&E works collaboratively with environmental groups, renewable energy developers and other stakeholders to encourage sound policies through a Renewable Energy Working Group, an informal and diverse group working to protect ecosystems, landscapes and species, while supporting the timely development of energy resources in the California desert and other suitable locations. Long-term and comprehensive planning and permitting processes can help better inform and facilitate renewable development.

PG&E is hopeful that these and other efforts will establish clear requirements that developers and other interested parties can satisfy in advance of the submission of offers to PG&E's future solicitations, and will, as a result, help decrease the time it takes parties to site and permit projects while ensuring environmental integrity.

Permitting challenges for projects are improving as a result of these and other efforts to streamline and adjust the permitting process for renewable energy projects. While these improvement efforts are ongoing, permitting and siting hurdles remain for renewables projects. Common issues may include challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, protected species, and county-imposed moratoriums. These hurdles may impact development schedules for projects.

5.1.3. Transmission and Interconnection

Achieving timely interconnection is an important part of the project development process. Delays in achieving interconnection can occur for various reasons, including the delay of substation construction, permitting issues, telecommunications delays, or overly aggressive timeline assumptions on the part of interconnection customers. While delays in interconnection can lead to delays in project development, such delays to date have not had a major impact on PG&E's ability to meet its RPS procurement targets.

Over the past few years, the CAISO and the IOUs have seen significant increases in the number of requests for grid interconnection. As the number of proposed RPS-eligible projects continues to increase in California, planning for how these projects would be connecting into the California grid has become increasingly challenging. Additionally, projects often withdraw from the interconnection process for a variety of reasons, including a lack of commercial viability, and these withdrawals significantly impact other projects that remain active and change the system planning assumptions. This in turn makes identifying upgrades and associated costs a dynamic process that can be challenging for both IOUs and interconnection customers to manage, increasing the need for effective queue management.

Accordingly, PG&E has initiated a number of internal efforts and collaborated on external initiatives to address these challenges at both the transmission and distribution levels. Recent notable changes in the distribution-level interconnection process included: (1) amending the Wholesale Distribution Tariff in October 2014 to address modifications similar to those made to the CAISO's Tariff; and (2) amending Rule 21 in January 2015 to capture the technological advances offered by smart inverters. Additional amendments to the Wholesale Distribution Tariff are underway currently to address recent proposals for a Distributed Group Study Process and project naming conventions, and to clarify financial security requirements and procedures.

Additionally, over the past few years, PG&E has worked with the CAISO and industry stakeholders in ongoing stakeholder initiatives enhancing the transmission-level interconnection processes. Most significant among the changes has been the Generator Interconnection and Deliverability Allocation Procedures ("GIDAP"), which has streamlined the process for identifying customer-funded transmission additions and upgrades under a single comprehensive process. This initiative also provides incentives for renewable energy developers to interconnect to the CAISO grid at the most cost-effective locations. PG&E has also actively contributed to the CAISO's Interconnection Process Enhancements stakeholder initiative that seeks to continuously review potential enhancements to the generator interconnection procedures.

More recently, PG&E is supporting the Renewable Energy Transmission Initiative 2.0 ("RETI 2.0") that was initiated jointly by the California Energy Commission, CPUC, CAISO, and the California Natural Resources Agency to facilitate electric transmission coordination and planning towards achieving California's 2030 goals. While RETI 2.0 is not a regulatory proceeding, PG&E supports RETI 2.0 as an initiative that can help inform future transmission planning proceedings.[32]

PG&E is supportive of the CAISO's and Commission's recent efforts to examine the potential impact of energy only ("EO") resources on transmission planning. The CAISO's 2015-2016 Transmission Plan included an informational "Special Study" that included energy only resources, and the CAISO's upcoming 2016-2017 Transmission Planning Process ("TPP") will help further that analysis.[33] In addition, the Commission has updated the RPS Calculator to include 50% RPS scenarios that consider the potential procurement of energy only resources.[34] PG&E is actively supporting these initiatives.

Partially deliverable and energy only contracts are currently a viable option for some renewable resources, and PG&E supports the ongoing study of the relative costs and benefits of energy only versus full deliverability. PG&E believes the current Least-Cost Best-Fit ("LCBF") methodology adequately captures the benefits and costs of the tradeoff between EO and full deliverability via the value of Resource Adequacy and the transmission cost adder. PG&E believes the current planning processes, including the Commission's IRP/Long-Term Procurement Plan ("LTPP"), and CAISO's TPP and GIDAP, are the proper venues to re-examine the transmission and sub-transmission needs for EO projects.

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32 *See* RETI 2.0 Website at http://www.energy.ca.gov/reti/.

33 *See* CAISO Website at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.

34 *See* CPUC Website at http://www.cpuc.ca.gov/RPS_Calculator/.

5.2. Consideration of Compliance Delay Risks in PG&E's RPS Strategy

Despite the ongoing efforts to address the potential delays noted above, challenges remain that could ultimately impact PG&E's RPS position. Moreover, operational issues, such as curtailment, may impact PG&E's RPS compliance. This section describes briefly some of the steps PG&E is taking to mitigate these risks.

5.2.1. Curtailment of RPS Generating Resources

As discussed in more detail in Section 11, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may reduce the RPS energy available for compliance. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 6.2.

5.2.2. Risk-Adjusted Analysis

PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. As described further in Section 6, deliveries from projects experiencing considerable development challenges associated with project financing, permitting, transmission and interconnection, among others, are excluded from PG&E's net short calculation.

PG&E's experience with prior solicitations is that developers often experience difficulties managing some of the development issues described above. As described in Section 8, PG&E's expected RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio, which are captured in PG&E's deterministic model.[35] These deterministic results do not account for all of the risks and uncertainties that can cause substantial swings in PG&E's portfolio.

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35 As described in Section 3.2.1, PG&E currently assumes a project development success rate of 100% in its deterministic model.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 50% RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

6. Risk Assessment

Dynamic risks, such as the factors discussed in Section 5 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. To account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales uncertainty and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[36] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at

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36 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.[37]

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 6.1 identifies the three risks accounted for in PG&E's deterministic model. Section 6.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 6.3 describes how the risks described in the first two sections are incorporated into both models, including details about how each model operates and the additional boundaries each sets on the risks. Section 6.4 notes how the two models help guide PG&E's optimization strategy and procurement need. Section 7 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices C.1 and C.2. Section 8 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

6.1. Risks Accounted for in Deterministic Model

PG&E's deterministic approach models three key risks:

1) <u>Standard Generation Variability</u>: the assumed level of deliveries for categories of online RPS projects.

2) <u>Project Failure</u>: the determination of whether or not the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.

3) <u>Project Delay</u>: the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

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[37] PG&E has also developed a framework to assess whether to hold or sell excess RPS volumes, included in Appendix J.

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

TABLE 6-1
DETERMINISTIC MODEL RISKS

RISK	METHODOLOGY	APPLIES TO
Standard Generation Variability	• For non-QF projects executed post-2002, 100% of contracted volumes • For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries • Hydro QFs, UOG and Irrigation District and Water Agency ("ID&WA") generation projections are updated to reflect the most recent hydro forecast.	Online Projects
Project Failure	• In Development projects with high likelihood of failure are labeled "OFF" (0% deliveries assumption) • All other In Development projects are "ON" (assume 100% of contracted delivery)	In Development Projects
Project Delay	• Professional judgment/Communication with counterparties	Under Construction Projects/ Under Development Projects/ Approved Mandated Programs

6.1.1. Standard Generation Variability

With respect to its operating projects, PG&E's forecast is divided into three categories: non-QF; non-hydro QFs; and hydro QF projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is typically based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, normalized for average water year conditions, and then adjusted to reflect PG&E's latest internal hydro outlook. The UOG and IDWA forecast are based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix G.

6.1.2. Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0% deliveries) and ON (represented with 100% deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

1. **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":

    - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.);
    - Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data);
    - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization;
    - Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability;
    - Whether a PPA amendment has been executed but has not yet received regulatory approval; and
    - Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as "Closely Watched."[38] PG&E does not currently have any in-development projects categorized as "OFF" in its deterministic model.

2. **ON** – Projects in all other categories are assumed to deliver 100% of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of "ON" projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of "ON" projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of "ON" projects represents executed and future contracts from Commission-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes within a reasonable timeline.

6.1.3. Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

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[38] For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

6.2. Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E's RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E's portfolio. PG&E's stochastic model assesses the impact of both demand- and-supply-side variables on PG&E's RPS position from the following four categories:

1) Retail Sales Uncertainty: This demand-side variable is one of the largest drivers of PG&E's RPS position;
2) Project Failure Variability: Considers additional project failure potential beyond the "on-off" approach in the deterministic model;
3) Curtailment: Considers buyer-ordered (economic), CAISO-ordered or Participating Transmission Owner ("PTO")-ordered curtailment; and
4) RPS Generation Variability: Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year to year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 6-2
CATEGORIZATION OF IMPACTS ON RPS POSITION

Higher Impact on RPS Position

Impact	Categorization
1. Retail Sales Uncertainty: Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** (*If an outcome occurs, the effect persists through more than one year).*
2. Curtailment: Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
3. RPS Generation Variability: Variability in yearly generation is largely an annual phenomenon that has little persistence across time.	**Variable and short-term** (*If an outcome occurs, the effect may only occur for the individual year.)*
4. Project Failure Variability: Lost volume from project failure persists through more than one year.	**Variable and persistent**

Lower Impact on RPS Position

6.2.1. Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, energy efficiency, levels of DA and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on energy efficiency, electric vehicles, and distributed generation. However, the variability in load loss due to DA and CCA is not modeled in this same way. As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting substantial increases in DA. Load loss due to CCA departure is modeled as [redacted] based on a forecast of CCA departure. Because forecast errors tend to carry forward into future years, the cumulative impact of load forecast uncertainty grows with time. Appendix F.1 lists the resulting simulated retail sales and summary statistics for the period 2016-2030. Appendix F.5 shows the resulting simulated RPS target when accounting for the retail sales uncertainty for the period 2016-2030.

6.2.2. RPS Generation Variability

Based on analysis of historical hydro generation data from 1985-2012, wind generation data from 1985-2011, and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is uncorrelated among technologies. Appendix F.3 lists the resulting simulated generation and summary statistics for the period 2016-2030.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes, Appendix F.4 combines the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, and shows how these variables interact.

6.2.3. Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). Curtailment ramps from a historical level of [redacted]

[redacted].[39] These modeling assumptions will not necessarily reflect the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information regarding curtailment.

6.2.4. Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower.

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39 [redacted]

Appendix F.2 lists PG&E's simulated failure rate and summary statistics for the period 2016-2030.

6.2.5. Comparison of Model Assumptions

Table 6-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, RPS generation, and curtailment. Section 7 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 6-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty[40]	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years (Appendix C.1); Uses most recent PG&E bundled retail sales forecast for all years (Appendix C.2).	Distribution based on most recent (2016) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success.
3) RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes. For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries. Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4) Curtailment	None	Curtailment is modeled as increasing between the following data points: [redacted] in 2015 [redacted] in 2020 [redacted] in 2024 [redacted] in 2030

40 These modeling assumptions will not necessarily align with the future actual sales, project failure rates, RPS generation, and curtailment hours, but are helpful in terms of considering the impact of uncertainty on long-term RPS planning and compliance.

6.3. How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

6.4. How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives; (b) inputs; and (c) constraints of the model:

   (a) The objective is to minimize procurement cost.

   (b) The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes[41]) in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] annually.

   (c) The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted], less than [redacted], less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

41 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, this modeling approach assumes re-contracting will be considered in the future side-by-side with procurement of other new resources.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.
3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.
4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not allow for price arbitrage through sales of PG&E's Bank in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2016 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this 2016 RPS Plan.

6.5. Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the 50% RPS are shown in Row La of PG&E's Alternate RNS in Appendix C.2.

The results of both the deterministic and stochastic models are discussed further in Section 7 and minimum margin of procurement is addressed in Section 8.

7. Quantitative Information

As discussed in Section 6, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix C. Appendix C.1 presents the RNS in the form required by the *Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendix C.2 is a modified version of Appendix C.1 to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its Bank size and PG&E's analysis of the minimum bank needed. However, in approving the 2015 RPS Plan, the Commission expressly rejected any specific bank size proposal.[42]

7.1. Deterministic Model Results

Results from the deterministic model under a 50% RPS target are shown as the physical net short in Row Ga of Appendices C.1 and C.2. Appendix C.1 provides a physical net short calculation using PG&E's April 2016 Bundled Retail Sales Forecast for years 2016-2020 and the LTPP sales forecast for 2021-2036,[43] while Appendix C.2 relies exclusively on PG&E's internal Bundled Retail Sales Forecast. Following the methodology described in Section 6.1, PG&E currently estimates a long-term volumetric

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42 D.15-12-025, pp. 106-107.

43 Sales forecast used is from the most recently approved bundled sales forecast filed in PG&E's 2014 Conformed Bundled Procurement Plan in AL 4750-E and approved June 15, 2016.

success rate of 100% for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendix C.2. This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 5, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendix C.2 depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.

7.1.1. 50% RPS Target Results

Under the current 50% RPS target, PG&E is well-positioned to meet its second (2014-2016), third (2017-2020), and fourth (2021-2024) compliance period RPS requirements. As shown in Row Gb of Appendix C.1, the deterministic model shows a forecasted second compliance period RPS Position of 29.9%, a third compliance period RPS position of [redacted], a fourth compliance period RPS position of 32.3%, a fifth compliance period RPS position of 30.2%, and a sixth compliance period RPS position of 29.2%. Row Ga of Appendix C.2 also shows a physical net short of 433 GWh beginning in 2026.

7.2. Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for the 50% RPS target. Because PG&E uses its stochastic model to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix C.2 for the 50% RPS target. Appendix C.1 provides an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendix C.2, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size.

Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

7.2.1. Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target

To evaluate possible procurement strategies, PG&E selected the following non-compliance risk targets for each future compliance period: [redacted]

Figure 7-1 shows the model's forecasted procurement need and resulting Bank usage under the 50% RPS by 2030 target. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2 provides the detailed results. Annual forecasted Bank usage is shown in Row La of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by [redacted]. The [redacted] SONS is [redacted] than the physical net short in Row Ga for [redacted], as the SONS [redacted]

[redacted]. Should PG&E engage in RPS sales, its position will be updated in subsequent RPS Plans to reflect an earlier procurement need year.

[redacted]

[redacted]

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

7.2.2. Bank Size Forecasts and Results

Figure 7-2 shows PG&E's current and forecasted cumulative Bank from the first compliance period through 2033. PG&E's total Bank size as of the end of the first compliance period is approximately 900 GWh. The stochastic model's results currently project PG&E's Bank size to [redacted] GWh by [redacted] (as shown in Figure 7-2, as well as in Appendix C.2, Row J). [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases. [redacted]

7.2.3. Minimum Bank Size

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted].[44] The difference between delivery and target can be thought of as the potential “need” (if negative) or “surplus” (if positive) that PG&E has in any one year.

Figure 7-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted]

Based on current model assumptions and inputs, Figure 7-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level. As discussed above in Section 7.2.1, PG&E has selected cumulative non-compliance risk targets of [redacted].

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44 [redacted]

[redacted]

[redacted]

As stated in Section 7.2.2, the stochastic model's results show PG&E's forecasted [redacted], PG&E's strategy is to procure steady, incremental volumes in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs and maintain minimum Bank levels. [redacted]

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 7-3 illustrates.

7.3. Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales of surplus procurement. Consistent with the Commission's adopted RNS methodology, PG&E's physical net short and cost projections do not include any projected sales of bankable contracted deliveries. However, PG&E is proposing as a part of its 2016 RPS Plan a framework for assessing whether to hold or sell surplus RPS volumes. PG&E will update its physical RNS in future RPS Plans if it executes any such sale agreements.

8. Margin of Procurement

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to: (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 50% RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

8.1. Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[45] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[46]

As described in more detail in Section 6, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract). PG&E considers this deterministic result to be its current statutory margin of procurement.[47] However, as discussed in Sections 6 and 7, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

8.2. Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin

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45 Cal. Pub. Util. Code § 399.13(a)(4)(D).

46 *Id.*, § 399.15(b)(5)(B)(iii).

47 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums.

of procurement.[48] As discussed further in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

While PG&E's current optimization strategy projects the use of a portion of PG&E's projected Bank to meet compliance requirements [redacted], PG&E believes it would be imprudent to use its entire projected Bank toward meeting its RPS compliance, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, holding a minimum Bank will reduce non-compliance risk, helping to avoid long-term over-compliance above the 50% RPS target and thus reducing long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 6 and 7.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

9. Bid Selection Protocol

As described in Sections 3 and 7, PG&E is well positioned to meet its RPS targets, under a 50% RPS target, until at least [redacted]. As a result, PG&E proposes not to hold a 2016 RPS procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2016 and 2017 through other Commission-mandated programs, such as the ReMAT and BioRAM Programs. To reflect PG&E's proposal not to hold a 2016 RPS procurement solicitation, language has been added throughout the 2016 RPS Plan to confirm that PG&E is required to seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2016 RPS Plan,

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48 Cal. Pub. Util. Code § 399.13(a)(4)(D).

except for RPS amounts that are separately mandated. Thus, PG&E is not including in the 2016 RPS Plan a solicitation protocol for procuring additional RPS resources, nor is it including an evaluation methodology for such purchases.

PG&E has included in Section 19 below and in confidential Appendix J a description of the framework PG&E proposes to use to assess whether to hold or sell excess RPS volumes. If the Commission approves the proposed framework, PG&E expects to conduct one or more solicitations in 2017 for short-term sales of bundled RPS volumes. PG&E anticipates selling short-term products based on its position, and may consider longer term offers in the future. PG&E has included a solicitation protocol and *pro forma* sales agreement as Attachment I to this 2016 RPS Plan. The pro forma sales agreement is largely unchanged from the Power Purchase and Sale Agreement adopted in the 2014 RPS Plan. The draft protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price.

PG&E anticipates minimal negotiations with respect to the form sales agreement and proposes filing the sales agreement by Tier 1 Advice Letter for Commission approval. This approach is consistent with the streamlined Tier 1 Advice Letter process authorized in D.14-11-042 for short-term sales agreements. In that decision, the Commission determined that a Tier 1 Advice Letter process could be utilized[49] as long as a utility has included a pro forma short-term contract as part of its approved RPS plan filing and the contract term is under 5 years. Streamlined processes for both RFO administration and Commission approval are required in order to allow for transactions to begin in 2017.

9.1. Proposed Time of Delivery Factors

PG&E sets its Time of Delivery ("TOD") factors based on expected hourly prices. Given the high penetration of solar generation expected through 2020 and beyond, PG&E forecasts that there will be significant periods of time during the mid-day when

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[49] D.14-11-042, pp. 74-78, and implemented in PG&E's approved 2014 RPS Plan.

net loads are low, resulting in prices that will be low or negative, especially in the spring. This expectation is consistent with forecasts of net load that have been publicized by the CAISO.[50] In addition, given the low mid-day loads, PG&E sees its peak demand (and resulting higher market prices) moving to later in the day, and as result, shifted its TOD periods in 2015. Capacity value has also become significantly less important in the selection process because: (1) market prices for generic capacity are low; and (2) net qualifying capacity using effective load carrying capability is also low. Thus, PG&E simplified its PPAs in 2015 and included only a single set of TOD factors to be applied to both energy-only and fully deliverable resources.

PG&E is keeping TOD periods unchanged, but updating its TOD factors as follows:

TABLE 9-1
RPS TIME OF DELIVERY FACTORS

	Peak	Mid-Day	Night
Summer	1.515	0.713	1.003
Winter	1.484	0.674	1.155
Spring	1.109	0.491	0.926

9.2. Workforce Development

SB 2 (1X) added a requirement that the LCBF criteria for ranking and selecting RPS resources shall include "the employment growth associated with the construction and operation of eligible renewable energy resources."[51] The Ruling directs the IOUs to include a description of a proposed approach for assessing and differentiating the ability of different bids to contribute to employment growth during the construction and operational phases of the project.[52]

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50 *See*, *e.g.*, *CAISO Transmission Plan 2014-2015*, pp. 162-163 (approved March 27, 2015) (available at http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf).

51 Cal. Pub. Util. Code § 393.13(a)(4)(A)(iv).

52 Ruling, p. 14.

PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E's LCBF methodology does include a qualitative assessment of the extent to which the proposed development supports RPS goals. It is based on information provided by the Seller and PG&E's assessment of that information. If PG&E were procuring RPS resources, it would require bidders to submit information on projected California employment growth during construction and operation. This would include number of hires, duration of hire, and indication of whether the bidder has entered into Project Labor Agreements or Maintenance Labor Agreements in California for the proposed project. This information was required from bidders in PG&E's 2014 RPS RFO.[53]

9.3. Disadvantaged Communities

SB 2 (1X) also added the requirement that preference shall be given "to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."[54] The Ruling directs the IOUs to include a description of their methodology for preferring projects that provide those benefits.[55]

As explained above, PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E has included this component as part of its assessment of an offer's consistency with and contribution to California's goal for the RPS Program. PG&E's LCBF methodology includes a qualitative assessment of the

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53 Attachment J2 to 2014 RPS RFO Protocol.

54 Cal. Pub. Util. Code § 399.13(a)(7).

55 Ruling, p. 15.

extent to which the proposed development supports RPS goals is based on information provided by the Seller, and PG&E's assessment of that information.

If PG&E were procuring resources, it would expect to solicit information from bidders similar to what was required in the 2014 RPS RFO.[56] PG&E asked bidders to respond to the following questions on this topic:

> Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels? If so, the Participant is encouraged to describe in its Offer, if applicable, how its proposed facility can provide the following benefits to adjacent communities:
>
> - Projected hires from adjacent community (number and type of jobs),
> - Duration of work (during construction and operation phases),
> - Projected direct and indirect economic benefits to the local economy (i.e., payroll, taxes, services),
> - Emissions reduction - Identify existing generation sources by fuel source within 6 miles of proposed facility; Will the proposed facility replace/supplant identified generation sources?
>   - If "yes", provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much MWh/year), and avoided emissions released into the community (within 6 miles of the project).
>   - If "No", why not?
>
> In D.04-07-029, the CPUC identified benefits to low income or minority communities, environmental stewardship, local reliability, repowering, and resource diversity as factors to be incorporated in PG&E's Offer evaluation. The Participant is encouraged to describe in its Offer(s) how its Eligible Renewable Resource ("ERR") facility can provide these benefits. If known, list any existing or proposed generation projects within a one-mile radius of the Project offered into this Solicitation.

10. Consideration of Price Adjustment Mechanisms

The Ruling requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index ("CPI"), price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially

56 Attachment J2 to 2014 RPS RFO Protocol.

incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[57]

In this 2016 RPS Plan, PG&E is proposing not to hold an RPS solicitation in 2016 and it does not plan to procure additional RPS volumes in 2017, other than through mandated programs. If PG&E was negotiating PPAs for additional procurement, PG&E might consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the legislature has found is a benefit of the RPS Program.[58] In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[59]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar

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57 Ruling, p. 15.

58 Cal. Pub. Util. Code § 399.11(b)(5).

59 D.11-04-030, pp. 33-34.

panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the CPI. The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

11. Economic Curtailment

In D.14-11-042, the Commission directed that the IOUs describe in future RPS Plans how "expected economic curtailment affects their RPS procurement."[60] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the Procurement Review Group ("PRG").[61] In June 2016, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E's observations and issues related to economic curtailment both for the market generally, and PG&E's specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in the first half of 2016 has broadly increased in the Real-Time Markets ("RTM") for the PG&E Default Load Aggregation Point ("DLAP") and for the North of Path 15 Hub ("NP15 Hub"). During January through June 2016, negative price intervals in the CAISO Five Minute Market for the PG&E DLAP occurred in approximately 6.6% of the 5-minute intervals, compared to approximately 4% during the same period in 2015. Similarly, NP15 Hub prices for this period in 2016 were negative approximately 6.8% of the 5-minute intervals compared to approximately 3.6% during this period in 2015. The

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60 D.14-11-042, p. 45.

61 *Id.*, pp. 42-43.

ZP26 Hub prices for 2016 in this period were negative approximately 8.3% of the intervals, roughly equal to the 2015 results for this same period. The specific occurrences of negative price periods and overgeneration events are largely unpredictable; [redacted][62] [redacted] PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. This also includes the incremental costs of compliance instruments required to comply with RPS targets. PG&E provided more detail concerning its RPS bidding strategy in its Bundled Procurement Plan ("BPP")[63] which was approved by the Commission in D.15-10-031.

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62 [redacted]

63 See PG&E, 2014 Bundled Procurement Plan, Appendix K (Bidding and Scheduling Protocol).

[redacted][64] [redacted][65]

While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods and also CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events.

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. [redacted][66] These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment

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64 [redacted]

65 [redacted]

66 [redacted]

events and update its curtailment assumptions as needed. Implementation of these assumptions in PG&E's modeling is discussed in more detail in Section 6.2.3.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in negative pricing events.

12. California Tree Mortality Emergency Proclamation

On October 30, 2015 the Governor declared a state of emergency to address epidemic tree mortality in California, stating that this epidemic mortality presents an enhanced threat to life, safety, and property from falling trees, and exacerbates wildfire risk.[67] The Emergency Proclamation is intended to mobilize resources for the safe removal of the hazardous trees. PG&E has been actively involved in the State's implementation of the Proclamation and remains committed to working closely with the Commission, California Department of Forestry and Fire Protection, Governor's Office, and all stakeholders to address this crisis.

Below, PG&E addresses the three issues identified in the Ruling related to the Emergency Proclamation.

12.1. PG&E's Biomass Portfolio

PG&E's biomass portfolio, in Table 12-1 below, consists of two different types of contracts: legacy Standard Offer Qualifying Facility Power Agreements (QF PPA) or contracts entered into as a result of required Renewables Portfolio Standard procurement (RPS PPA). QF PPAs receive a payment for energy delivered and an additional capacity payment based on energy delivered during specific hours. The energy price paid to QFs is based upon a monthly Short-Run Avoided Cost calculation or a bilaterally negotiated price subsequently approved by the Commission. Prices for QFs shown in Table 12-1 represent historical costs for energy and delivered capacity

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67 Ruling, pp. 16-17; see also Governor Brown's State of Emergency Proclamation, issued on October 30, 2015 (available at: https://www.gov.ca.gov/docs/10.30.15_Tree_Mortality_State_of_Emergency.pdf).

expressed on a dollar per MWh basis. The RPS PPAs are paid a single all-in price for energy and capacity. The RPS prices shown represent the levelized price of energy included in the advice letter seeking approval of the transaction.

PG&E has entered into several contract amendments to respond to the Emergency Proclamation. On April 1, 2016, PG&E filed an advice letter asking the Commission to approve a contract amendment for five biomass facilities.[68] The advice letter was approved on June 9, 2016.[69] In addition, on June 3, 2016, PG&E filed advice letters asking the Commission to approve short-term extensions of the pricing amendments to existing QF PPAs with two biomass facilities.[70] The proposed amendments would further the goals of the Emergency Proclamation by helping to ensure that these two biomass facilities, which are located in areas of the state significantly impacted by tree mortality, will continue to operate and be available as a way to dispose of HHZ fuel through the end of the high forest fire danger season.

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68 See Advice Letter 4818-E.

69 See Commission Resolution E-4786.

70 See Advice Letter 4851-E.

TABLE 12-1
PG&E'S BIOMASS PORTFOLIO

Name	Contract Expiration Date	Capacity (MW)	City	County	QF Historical Payments Price or RPS Contract Price ($/MWh)	Maximum Price Under Price Amendment	Price Amendment Expiration Date
PG&E's QF and FIT Biomass Contracts[71]							
1. Pacific-Ultrapower Chinese Station (Ogden Power Pacific, Inc.)	1/23/2017	22	Jamestown	Tuolumne	93.42	$100.43	10/31/16
2. DG Fairhaven Power	2/2/2017	17.25	Fairhaven	Humboldt	104.52	$107.42	1/31/16
3. Wheelabrator Shasta	4/30/2018	54.9	Anderson	Shasta	94.65	$100.43	7/31/16
4. Rio Bravo Fresno	2/12/2019	26.5	Fresno	Fresno	98.77	$100.43	10/31/16
5. HL Power	9/15/2019	32	Wendel	Lassen	99.56	$101.26	7/31/16
6. Burney Forest Products	1/2/2020	31	Burney	Shasta	[redacted]	[redacted][72]	8/31/16
7. Rio Bravo Rocklin	3/16/2020	25	Rocklin	Placer	98.99	100.43	7/31/16
8. Thermal Energy Dev. Corp.	5/30/2020	21	Tracy	San Joaquin	98.82	N/A	N/A
9. Humboldt Redwood Company (Eel River Power Facility)	evergreen	22	Scotia	Humboldt	98.95	N/A	N/A
10. Ortigalita Power Company (1969/FiT)	6/16/2026	0.75	Merced	Merced	103.50	N/A	N/A
PG&E's RPS Biomass Contracts[73]							
11. Mt. Poso	2/20/2027	44	Bakersfield	Kern	141.12	N/A	N/A
12. El Nido Biomass Facility	2/8/2031	9	Merced	Merced	121.62	N/A	N/A
13. Chowchilla Biomass Facility	2/8/2031	9	Chowchilla	Madera	121.62	N/A	N/A
14. Wadham Energy LP	5/31/2018	26.5	Williams	Colusa	95.66	N/A	N/A
15. Woodland Biomass	2/29/2020	25	Woodland	Yolo	102.06	N/A	N/A
16. SPI Biomass Portfolio:[74] Burney Lincoln Quincy Sonora Anderson II	9/8/2035	58	Anderson Lincoln Quincy Sonora Anderson	Shasta Placer Plumas Tuolumne Shasta	[redacted]	N/A	N/A
DTE Stockton	2/20/2039	44.5	Stockton	San Joaquin	[redacted]	N/A	N/A

71 The QF and FIT payments shown in Table 12-1 represent the average historical costs for energy and delivered capacity expressed on a $/MWh basis for the years 2013-2015. This data is consistent with the payments reported in the annual Padilla data request for 2013-2015. Contracts 1-9 in Table 12-1 are QF contracts.

72 [redacted]

73 The RPS prices represent the levelized price of energy as represented in the advice letters seeking approval of these contracts.

74 On June 9, 2016, the Commission approved an amendment to PG&E's RPS contract with SPI which allows for up-to an additional 21 MW of capacity from the five existing biomass facilities. The incremental generation will be produced from fuel recovered in response to the Governor's Emergency Proclamation and other declared drought-related emergencies.

12.2. Benefits of Biomass Contracts in PG&E's Renewable Portfolio

12.2.1. Contribution to RPS

PG&E has historically been, and continues to be, the primary purchaser of electricity generated by in-state biomass resources. Biomass is an important component of PG&E's renewables portfolio. For example, in 2015, biomass represented nearly 14% of PG&E's RPS generation. PG&E procured over 90% of all biomass contracted to IOUs in California in 2015, and in 2016, PG&E expects to be the sole buyer of biomass among IOUs outside of the recently established targeted BioRAM procurement mechanism.[75] Additionally, because biomass resources contribute to its RPS compliance, PG&E renegotiated or restructured biomass PPAs to allow continued operations of several facilities in 2011. However, while biomass continues to play an important role in PG&E's diverse portfolio of resources, biomass projects are currently less competitive and less flexible than some alternative renewable energy sources. Furthermore, as described in Sections 3.3 and 7, as well as Appendix C, PG&E has no current need for incremental RPS-eligible procurement, including biomass procurement.

12.2.2. Portfolio Fit

While biomass facilities provide RPS-eligible energy, there are also significant operational challenges associated with biomass. For example, biomass is a baseload resource. This means that while generation output may be more predictable than for a variable resource (e.g., wind or solar), biomass resources have less ability than some other more flexible resources to adjust output levels in response to market or system conditions. As California moves towards meeting a 50% RPS, increased ramping capability will be needed to accommodate growing variability and uncertainty associated with the integration of intermittent renewable resources. An increase in baseload

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[75] See 2014 Preliminary Annual 33% RPS Compliance Report of Pacific Gas and Electric Company (Filed February 26, 2015); Southern California Edison Company's (U 338-E) 2014 Preliminary Annual 33% Renewables Portfolio Standard Compliance Report (Filed September 4, 2015); San Diego Gas and Electric Preliminary Annual 33% RPS Compliance Report (September 4, 2015).

capacity (such as biomass) that cannot be economically dispatched by the CAISO market may further increase the potential for overgeneration, since such inflexible capacity, if it has to be taken, would require the CAISO to economically or physically curtail generation from other resources in order to balance load and resources.

12.2.3. Societal Benefits

In addition to providing energy and contributing to the state's RPS targets, various social benefits are ascribed to biomass generation, including job preservation and wildfire hazard risk reduction. The Commission and the Governor have previously noted the potential for these benefits, and the Commission has developed BioRAM in response to the Proclamation. BioRAM utilizes the existing RAM process to mandate a minimum of 50 MW of biomass generation statewide in an attempt to provide additional disposal options for biomass fuel in the highest fire hazard zones of the State.

Although PG&E has played an active role in developing biomass procurement programs, any discussion of societal benefits should be part of a larger conversation focusing on how the state can foster a longer-term, sustainable structure for funding biomass investment. A sustainable funding structure would provide public funding equivalent to the value of these broader societal benefits; ensuring that everyone who benefits from these investments help bear the incremental costs and the burden is not borne solely by PG&E's customers. Additionally, if biomass procurement is designed to provide broad societal benefits to all electricity customers, as is the case with BioRAM, those benefits should be paid by all benefitting customers and not only by the IOUs' bundled customers. PG&E has jointly proposed an appropriate non-bypassable charge for this purpose as part of the BioRAM proceeding.[76]

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[76] See Joint Petition for Modification of D.10-12-048, filed in R.08-08-009 on April 19, 2016. Appendix 3 of the Petition provides a detailed description of the mechanics that should be used for a non-bypassable charge.

12.3. Additional Emergency Proclamation-Related Procurement Alternatives

To the extent that the Commission explores additional Emergency Proclamation-related procurement, it should be based on a clear demonstration of need. Specifically, this demonstration should be based on three findings. First, any future mandates should be based on a demonstration of both the currently identified volume of high hazard forest material that must be removed and a projection of the expected volumes that will be available over the anticipated contract terms (i.e., 5, 10, 15 or 20 years). Second, any such order should first consider the capacity and costs of all disposal options, not only electricity generation. This should specifically include an investigation regarding whether alternative end-uses (*e.g.,* conversion of biomass to biogas for direct injection into the pipeline or use in the transportation sector) are cost-effective and viable. Finally, any such mandate should first determine that the costs of additional biomass procurement should be allocated to all benefitting customers because the procurement will provide demonstrated, quantifiable, and commensurate benefits to all electricity customers.

As mentioned above, PG&E is currently the only IOU procuring biomass in the state outside of BioRAM. If additional Emergency Proclamation-related procurement is determined to be necessary based on all of the above findings, all LSEs must either be required to participate, or costs must be allocated to all benefitting customers in California on a fully non-bypassable basis.

Additionally, the terms of any contracts resulting from additional mandated Emergency Proclamation-related procurement should be no greater than five years. Because bark beetle infestation is driven by a host of outside factors, like temperature and precipitation levels, the length of the crisis cannot be known in advance. A five-year term is enough to provide a predictable disposal outlet, while not burdening customers with unnecessary costs once these issues are mitigated.

Finally, facilities with short-term contracts from Emergency Proclamation-related procurement should be, at a minimum, subject to the same fuel verification requirements set forth in Resolution E-4770, which established the BioRAM Program, in order to effectively address the emergency conditions raised in the Proclamation.

13. Expiring Contracts

The Ruling requires PG&E to provide information on contracts expected to expire in the next 10 years.[77] Appendix E lists the projects under contract to PG&E that are expected to expire in the next 10 years. As indicated in Appendix G, PG&E's RNS calculations assume no re-contracting. Re-contracting is not precluded by this assumption, but rather it reflects that proposed = extensions of existing contracts will be evaluated against current offers.

14. Cost Quantification

This section summarizes results from actual and forecasted RPS generation costs (including incremental rate impacts), shows potential increased costs from mandated programs, and identifies the need for a clear cost containment mechanism to address RPS Program costs. Tables 1 through 4 in Appendix D provide an annual summary of PG&E's actual and forecasted RPS costs and Page 1 of Appendix D outlines the methodology for calculating the costs and generation.

14.1. RPS Cost Impacts

Appendix D quantifies the cost of RPS-eligible procurement—both historical (2003-2015) and forecast (2016-2030). From 2003 to 2015, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E incurred more than $2.4 billion in procurement costs for RPS-eligible resources in 2015.

RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate

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[77] Ruling, p. 17.

for RPS-eligible procurement and generation. While this formula does not provide an estimate of the renewable “above-market premium” that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix D illustrate the potential rate of growth in RPS costs and the impact this growth will have on average rates, all other factors being equal. Annual rate impact of the RPS Program increased from 0.7¢/kWh in 2003 to an estimated 3.6¢/kWh in 2016, meaning the average rate impact from RPS-eligible procurement has increased more than five-fold in approximately 13 years. This growth rate is projected to continue increasing through 2020, as the average rate impact is forecasted to increase to 4.5¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs resulting from the direct procurement of the renewable resources, there are incremental indirect transmission and integration costs associated with that procurement.

14.2. Cost Impacts Due to Mandated Programs

As PG&E makes progress toward achieving the 50% RPS goal, the cost impacts of mandated procurement programs that focus on particular technologies or project size increase over time, and procurement from those programs increasingly comprises a larger share of PG&E’s incremental procurement goals. In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets that allow only a subset of those options.[78] Studies have also shown that renewable electricity mandates increase prices and costs,[79] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants; and second, by creating a less robust market for participants to compete.[80] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

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78 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et al., "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/RFF/Documents/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

79 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call" (available at http://www.instituteforenergyresearch.org/pdf/statereport.pdf); Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

80 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

15. Imperial Valley

For the IOUs' 2014 RPS solicitations, the Commission did not specifically require any remedial measures to bolster procurement from Imperial Valley projects but required continued monitoring of IOUs' renewable procurement activities in the Imperial Valley area.[81] Even without remedial measures in PG&E's 2014 RPS Solicitation, the Independent Evaluator monitoring that solicitation found that:

> Overall, the response of developers to propose Imperial Valley projects was robust and PG&E's selection of Imperial Valley Offers was representative of that response. Arroyo perceives no evidence that PG&E failed in any way to perform outreach to developers active in the Imperial Valley or that there was any structural impediment in the RFO process that hindered the selection of competitively priced Offers for projects in the Imperial Valley.[82]

Given the robustness of the response from Imperial Valley projects in the 2014 RPS solicitation, as well as the 2013 RPS solicitation, and given the fact that PG&E is proposing not to hold a 2016 RPS solicitation, there does not appear to be a need to adopt any special remedial measures for the Imperial Valley as a part of the RPS Plan.

PG&E has one RPS PPA under contract for a project in the Imperial Valley. That project is in development. Commercial operation is expected in 2017, with deliveries under the PPA beginning in 2020.

16. Important Changes to Plans Noted

This section describes the most significant changes between PG&E's 2015 RPS Plan and its Draft 2016 RPS Plan. A complete redline of the draft 2016 RPS Plan against PG&E's 2015 RPS Plan is included as Appendix A of the 2016 RPS Plan. The table below provides a list of key differences between the two RPS Plans:

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81 D.14-11-042, pp. 15-16.

82 PG&E, *Advice Letter 4632-E*, p. 40, Section 2 (IE Report) (May 7, 2015).

Reference	Area of Change	Summary of Change	Justification
Entire RPS Plan	Consideration of the Higher RPS Requirements from SB 350	Includes updates to consider both the 33% by 2020 target and an assumed "straight-line" trajectory associated with the SB 350 compliance period targets towards 50% RPS in 2030	Ruling at pp. 4-5.
Section 9.2	Workforce Development	Includes discussion of consideration of workforce development during bid evaluation	Ruling at p. 14
Section 9.3	Disadvantaged Communities	Includes discussion of consideration of disadvantaged communities during bid evaluation	Ruling at p. 15
Section 18	California Tree Mortality Emergency Proclamation	Include response to the Specific Requirements for 2016 RPS Procurement Plans related to the Governor's Emergency Proclamation	Ruling at p. 16-17
Section 19	RPS Position Management and Sales of Surplus RPS Products	Includes discussion of a framework for assessing whether to hold or sell excess RPS volumes	Ruling at p. 8
Appendix J	Framework for Assessing Potential Sales of Excess RPS Volumes	Includes a framework for assessing whether to hold or sell excess RPS volumes	Ruling at p. 8

17. Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

17.1. Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2016 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct describes the safety of the public, employees and contractors as PG&E's highest priority.[83] PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, PG&E's Safety Commitment, Personal Safety Commitment and Keys to Life.[84] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E's testimony in its General Rate Case ("GRC"),[85] the top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ("OSHA") and the CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of

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83 *See* PG&E, "Employee Code of Conduct" (August 2013) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 3 (available at http://www.pgecorp.com/aboutus/ethics_compliance/con_con_ven/).

84 *See* PG&E, "Employee Code of Conduct" *supra* (describing the Safety Principles, Safety Commitment, Personal Safety Commitment and Keys to Life).

85 *See* PG&E, *Prepared Testimony, 2017 GRC, Application 15-09-001*, Exhibit (PG&E-5), Energy Supply, pp. 1-18 to 1-19 (available at http://www.pge.com/regulation/).

its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

With regard to employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance.

Employees also participate in an employee led Driver Awareness Team established for the sole purpose of improving driving. An annual motor vehicle incident ("MVI") Action Plan is developed and implemented each year. This action plan focuses on vehicle safety culture and implements the Companywide motor vehicle safety initiatives in addition to specific tools such as peer driving reviews and 1 800 phone number analysis to reduce MVIs.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Training and recertification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training

- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Employee injury case management
- Safety performance recognition
- Public safety awareness

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. With regard to public safety, PG&E has developed and implemented a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

PG&E will never be satisfied in its safety performance until there is never an injury to any of its employees, contractors, or members of the public. Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement change that can improve safety performance.

17.2. Development and Operation of Third-Party–Owned, RPS-Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. While this authority has not changed, PG&E developed additional contract provisions to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities. Additionally, the new provisions will seek to implement lessons learned and instill a continuous improvement safety culture that mirrors PG&E's approach to safety.

Specifically, the safety language that PG&E has developed builds upon the former standard of Good Utility Practices to a new standard of Prudent Electrical Practices, which includes greater detail on the types of activities covered by this standard, including but not limited to safeguards, equipment, personnel training, and control systems. This language was included in the recently executed 2014 Energy Storage agreements and could be incorporated in future RPS form PPAs if PG&E's RPS position resulted in a need for RPS procurement.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's

general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

PG&E receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including OSHA recordables and work stoppage information. Additionally, the new contract provisions would require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. If the generator has repeated safety violations or challenges, the generator could be at greater risk of failing to meet a key project development milestone or failing to meet a material obligation set forth in the PPA.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

18. Energy Storage

AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E submitted an application to procure energy storage resources on February 28, 2014. In D.14-10-045, the Commission approved PG&E's application with modifications. PG&E filed final storage RFO results for Commission approval on

December 1, 2015, and is awaiting Commission action on its Application. PG&E is also participating in a new proceeding, R.15-03-011, which the Commission opened in March 2015 to consider policy and implementation refinements to the energy storage procurement framework and program design. On March 1, 2016, PG&E submitted an application to procure storage as part of its 2016 Energy Storage RFO.

PG&E considers eligible energy storage systems to help meet its Energy Storage Program targets through its RPS procurement process, Energy Storage RFO, as well as other CPUC programs and channels such as the Self-Generation Incentive Program. PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[86]

19. RPS Position Management and Sales of Surplus RPS Products

As described in Section 7.2, PG&E forecasts its cumulative Bank to exceed the calculated minimum Bank size over the next ten years, in part due to changes to PG&E's retail sales forecast. Given this long position, PG&E is proposing a framework through which to assess whether PG&E should hold or sell excess bankable RPS volumes, and is requesting approval of this framework, detailed in Appendix J.

[redacted]

[redacted]:

86 *See* PG&E, *Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Resources (2014-2015 Biennial Cycle):* http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=3100).

- [redacted];
- [redacted][87]
- [redacted]

[redacted]

Based on current inputs to the framework described in Appendix J, PG&E expects to hold one or more solicitations for the sale of bankable, bundled renewable generation and RECs in 2017. PG&E anticipates selling short-term products based on its position, and may consider longer term offers in the future.

While PG&E will execute sales through solicitations, PG&E may simultaneously consider entering into bilateral contracts, and would seek additional approval from the Commission under those circumstances. Confidential Appendix I contains PG&E's proposed sales solicitation protocol and pro forma sales agreement. The pro forma sales agreement is largely unchanged from the Power Purchase and Sale Agreement adopted in the 2014 RPS Plan. The draft protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price. PG&E anticipates

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87 [redacted]

minimal negotiations with respect to the form agreement and proposes that these sales agreements be filed as Tier 1 Advice Letters for Commission approval.

APPENDIX B

Project Development Status Update

August 8, 2016

Appendix B: Project Development Status Update

Line No.	IOU ID	Project Name	Primary Developer	Technology Type	Contract Capacity (MW)	Expected Energy (GWh)	Energy Delivery Status	Vintage	CPUC Approval Status	Financing Status	Permit Status	Guaranteed Construction Start Date	Actual or Expected Construction Start Date	Construction Status	Status of Interconnection Agreement	Guaranteed COD	Actual or Expected COD
1	33R255	Kansas[1]	Dominion Solar Holdings, Inc.	Solar Photovoltaic	20	47	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	Complete	Complete	12/31/2016	12/26/2014
2	33R256	Lost Hills Solar	First Solar, Inc.	Solar Photovoltaic	20	47	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	Complete	Complete	12/31/2019	[redacted]
3	33R257	Cuyama Solar Array	First Solar, Inc.	Solar Photovoltaic	40	104	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	12/31/2019	[redacted]
4	33R258	Blackwell Solar	First Solar, Inc.	Solar Photovoltaic	12	28	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	Complete	Complete	12/31/2019	[redacted]
5	33R259	Henrietta Solar	SunPower	Solar Photovoltaic	100	244	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	10/1/2016	[redacted]
6	33R326	CED Lost Hills Solar	Con Edison Development	Solar Photovoltaic	20	48	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	8/3/2016	[redacted]
7	33R329	Diablo Winds (2)	NextEra Energy Resources, LLC	Wind	18	62	[redacted]	Existing	CPUC Approved	[redacted]	Complete	N/A	N/A (Existing)	Complete	Complete	7/1/2016	[redacted]
8	33R330	RE Astoria	Recurrent Energy	Solar Photovoltaic	100	298	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	1/3/2019	[redacted]
9	33R343	Midway Solar Farm I	Solar Frontier Americas Holding, LLC	Solar Photovoltaic	50	119	[redacted]	New	CPUC Approved	[redacted]	Complete	[redacted]	[redacted]	[redacted]	Complete	6/1/2020	[redacted]
10	33R344	California Flats Solar Project	First Solar Development, Inc.	Solar Photovoltaic	150	381	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Complete	12/31/2018	[redacted]
11	33R361	Maricopa West Solar	E.ON Climate and Renewables North America, LLC	Solar Photovoltaic	20	55	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	5/31/2017	[redacted]
12	33R362	Portal Ridge Solar C Project	DESRI PORTAL RIDGE DEVELOPMENT, LLC	Solar Photovoltaic	11	30	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	1/20/2017	[redacted]
13	33R363	SR Solis Oro Loma Teresina Solar Project A	Con Edison Development	Solar Photovoltaic	10	26	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	1/20/2017	[redacted]
14	33R364	Sunray 20	Cogentrix Solar Holdings, LLC	Solar Photovoltaic	20	51	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	1/20/2017	[redacted]
15	33R365	Avenal Solar Project A	Con Edison Development	Solar Photovoltaic	8	20	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	1/20/2017	[redacted]
16	33R366	SR Solis Oro Loma Teresina Solar Project B	Con Edison Development	Solar Photovoltaic	10	26	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	1/20/2017	[redacted]
17	33R367	Altech III	Ogin Inc.	Wind	20	53	[redacted]	Repowered	CPUC Approved	[redacted]	[redacted]	N/A	N/A (Existing)	[redacted]	[redacted]	11/1/2016	[redacted]
18	33R368	Avenal Solar Project B	Con Edison Development	Solar Photovoltaic	8	20	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	1/20/2017	[redacted]
19	33R374	CED Corcoran Solar 3	Con Edison Development	Solar Photovoltaic	20	49	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	Complete	Complete	5/30/2017	[redacted]
20	33R375	Westside Solar	Nextera Energy Resources, LLC and its subsidiary Aries Solar Holding, LLC	Solar Photovoltaic	20	55	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	5/30/2017	[redacted]
21	33R376	Aspiration Solar G	FTP Solar LLC	Solar Photovoltaic	9	23	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	5/30/2017	[redacted]
22	33R382	Bakersfield PV 1	Mirasol Development LLC	Solar Photovoltaic	5	13	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]		4/18/2018	[redacted]
23	33R383	Bayshore Solar A	FTP Power LLC, dba Sustainable Power Group (sPower)	Solar Photovoltaic	20	57	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
24	33R384	Bayshore Solar B	FTP Power LLC, dba Sustainable Power Group (sPower)	Solar Photovoltaic	20	57	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]

Appendix B: Project Development Status Update

Line No.	IOU ID	Project Name	Primary Developer	Technology Type	Contract Capacity (MW)	Expected Energy (GWh)	Energy Delivery Status	Vintage	CPUC Approval Status	Financing Status	Permit Status	Guaranteed Construction Start Date	Actual or Expected Construction Start Date	Construction Status	Status of Interconnection Agreement	Guaranteed COD	Actual or Expected COD
25	33R385	Bayshore Solar C	FTP Power LLC, dba Sustainable Power Group (sPower)	Solar Photovoltaic	20	57	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
26	33R386	San Joaquin 1B FIT	Solar Frontier Americas Development, LLC	Solar Photovoltaic	2	4	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
27	33R387	San Joaquin 1A	Solar Frontier Americas Development, LLC	Solar Photovoltaic	20	50	[redacted]	New	CPUC Approved	[redacted]	Complete	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
28	33R388	Bakersfield Industrial 1	Mirasol Development LLC	Solar Photovoltaic	1	2	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
29	33R389	Delano Land 1	Mirasol Development LLC	Solar Photovoltaic	1	3	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
30	33R390	Manteca Land 1	Mirasol Development LLC	Solar Photovoltaic	1	2	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
31	33R391	Merced 1	Green Light Energy Corporation	Solar Photovoltaic	3	6	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
32	33R392	RE Tranquillity 8 Amarillo	Recurrent Energy	Solar Photovoltaic	20	55	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	[redacted]	4/18/2018	[redacted]
33	33R393	Java Solar	SunPower Corporation, Systems	Solar Photovoltaic	14	36	[redacted]	New	CPUC Approved	[redacted]	[redacted]	N/A	[redacted]	[redacted]	Complete	4/18/2018	[redacted]
34	33R396	54KR 8me LLC	8minutenergy Renewables, LLC	Solar Photovoltaic	20	52	[redacted]	New	CPUC Approved	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Complete	4/18/2018	[redacted]

[1]The Kansas project achieved COD on 12/26/14, and is currently selling to a third party. PG&E will not start accepting energy deliveries from Kansas until the expected IEDD of 1/1/18.

APPENDIX C.1

Renewable Net Short Calculations

August 8, 2016

Table C.1: Renewable Net Short Calculation as of Apr 2016

Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2016 - 2020) and LTPP Methodology (2021 - 2036)

Variable	Calculation	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Actuals	2016 Forecast	2014-2016
		Forecast Year		-	-	-	CP1	-	-	-	CP2
		Annual RPS Requirement									
A		Bundled Retail Sales Forecast (LTPP)[1]		74,864	76,205	75,705	226,774	74,547	72,113	68,906	215,566
B		RPS Procurement Quantity Requirement (%)[2]		20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%
C	A*B	**Gross RPS Procurement Quantity Requirement (GWh)**		14,973	15,241	15,141	45,355	16,177	16,802	17,227	50,206
D		Voluntary Margin of Over-procurement[3]		-	-	-	-	-	-	-	-
E	C+D	**Net RPS Procurement Need (GWh)**		14,973	15,241	15,141	45,355	16,177	16,802	17,227	50,206
		RPS-Eligible Procurement									
Fa		Risk-Adjusted RECs from Online Generation[4]		14,699	14,513	17,212	46,424	20,207	21,285	22,952	64,443
Faa		Forecast Failure Rate for Online Generation (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb		Risk-Adjusted RECs from RPS Facilities in Development[5]		-	-	-	-	-	-	84	84
Fbb		Forecast Failure Rate for RPS Facilities in Development (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc		Pre-Approved Generic RECs		-	-	-	-	-	-	0	-
Fd		Executed REC Sales		-	-	(142)	(142)	(50)	-	(60)	(110)
F	Fa + Fb +Fc - Fd	Total RPS Eligible Procurement (GWh)[6]		14,699	14,513	17,069	46,281	20,157	21,285	22,976	64,418
F0		Category 0 RECs		14,651	13,049	14,163	41,863	16,899	17,409	18,200	52,509
F1		Category 1 RECs		48	1,464	2,906	4,418	3,257	3,875	4,776	11,908
F2		Category 2 RECs		-	-	-	-	-	-	-	-
F3		Category 3 RECs		-	-	-	-	-	-	-	-
		Gross RPS Position (Physical Net Short)									
Ga	F-E	**Annual Gross RPS Position (GWh)**		(274)	(728)	1,928	926	3,980	4,482	5,750	14,212
Gb	F/A	**Annual Gross RPS Position (%)**		19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	33.3%	29.9%
		Application of Bank									
Ha	H - Hc (from previous year)	Existing Banked RECs above the PQR[7,8]		-	(274)	(1,033)	-	861	4,815	[redacted]	
Hb		RECs above the PQR added to Bank		(274)	(728)	1,928	926	3,980	4,482	5,750	14,212
Hc		Non-bankable RECs above the PQR		-	31	34	65	26	25	27	78
H	Ha+Hb	Gross Balance of RECs above the PQR		(274)	(1,002)	895	926	4,841	9,297	[redacted]	
Ia		Planned Application of RECs above the PQR towards RPS Compliance[9]		-	-	-	-	[redacted]			
Ib		Planned Sales of RECs above the PQR[10]		-	-	-	-				
J	H-Ia-Ib	Net Balance of RECs above the PQR[7]		(274)	(1,002)	895	926				
J0		Category 0 RECs		-	-	-	-				
J1		Category 1 RECs		-	-	895	895				
J2		Category 2 RECs		-	-	-	-				
		Expiring Contracts									
K		RECs from Expiring RPS Contracts[11]		N/A	N/A	N/A	N/A	N/A	N/A	17	17
		Net RPS Position (Optimized Net Short)									
La	Ga + Ia – Ib – Hc	**Annual Net RPS Position after Bank Optimization (GWh)[12]**		(274)	(759)	1,894	861	[redacted]			
Lb	(F + Ia – Ib – Hc)/A	**Annual Net RPS Position after Bank Optimization (%)[12,13]**		19.6%	19.0%	22.5%	20.4%				

Variable	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024
(Forecast Year)	-	-	-	-	CP3	-	-	-	-	-
A	67,126	[redacted]		51,156	[redacted]	61,688	61,477	61,047	60,622	244,835
B	27.0%	29.0%	31.0%	33.0%	30.0%	34.8%	36.5%	38.3%	40.0%	37.4%
C	18,124	[redacted]		16,881	[redacted]	21,437	22,439	23,351	24,249	91,475
D	-	-	-	-	-	-	-	-	-	-
E	18,124	[redacted]		16,881	[redacted]	21,437	22,439	23,351	24,249	91,475
Fa	22,619	20,529	19,835	18,978	81,962	18,762	16,351	16,014	15,746	66,873
Faa	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb	833	1,048	1,938	2,006	5,825	2,045	2,034	2,023	2,017	8,119
Fbb	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc	44	433	846	1,002	2,325	1,006	1,004	1,003	1,003	4,016
Fd	-	-	-	-	-	-	-	-	-	-
F	23,496	22,010	22,619	21,986	90,112	21,813	19,390	19,040	18,766	79,008
F0	18,006	15,980	15,255	14,400	63,641	13,983	11,596	11,301	11,077	47,957
F1	5,490	6,030	7,364	7,586	26,470	7,830	7,793	7,739	7,689	31,051
F2	-	-	-	-	-	-	-	-	-	-
F3	-	-	-	-	-	-	-	-	-	-
Ga	5,372	[redacted]		5,105	[redacted]	376	(3,050)	(4,311)	(5,483)	(12,467)
Gb	35.0%			43.0%		35.4%	31.5%	31.2%	31.0%	32.3%
Ha	[redacted]									
Hb	5,372	[redacted]		5,105	[redacted]	376	-	-	-	376
Hc	94	-	-	-	94	-	-	-	-	-
H – J2	[redacted]									
K	396	2,552	3,245	4,109	10,301	4,449	6,811	7,105	7,381	25,745
La – Lb	[redacted]									

Variable	2025 Forecast	2026 Forecast	2027 Forecast	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033	2034 Forecast	2035 Forecast	2036 Forecast	2034- 2036
(Forecast Year)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A	60,369	60,116	59,865	180,350	59,615	59,366	59,118	178,100	58,871	58,625	58,381	175,878	58,137	57,894	57,652	173,683
B	41.7%	43.3%	45.0%	43.3%	46.7%	48.3%	50.0%	48.3%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	150.0%	83.3%
C	25,174	26,030	26,939	78,144	27,840	28,674	29,559	86,073	29,436	29,313	29,190	87,939	29,068	28,947	86,478	144,494
D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	25,174	26,030	26,939	78,144	27,840	28,674	29,559	86,073	29,436	29,313	29,190	87,939	29,068	28,947	86,478	144,494
Fa	15,638	15,089	14,831	45,558	14,776	14,210	14,146	43,132	13,374	12,844	11,620	37,838	10,631	9,576	8,946	29,153
Faa	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb	2,002	1,992	1,982	5,976	1,975	1,961	1,951	5,887	1,941	1,901	1,867	5,709	1,209	1,201	1,133	3,543
Fbb	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc	999	997	996	2,992	996	992	990	2,979	989	989	985	2,964	984	982	983	2,948
Fd	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	18,640	18,078	17,808	54,526	17,747	17,163	17,087	51,997	16,303	15,735	14,473	46,511	12,823	11,759	11,062	35,645
F0	10,999	10,460	10,216	31,676	10,166	9,633	9,589	29,390	8,891	8,792	8,168	25,850	7,537	7,088	7,082	21,707
F1	7,641	7,618	7,592	22,850	7,581	7,529	7,496	22,607	7,412	6,943	6,305	20,661	5,286	4,671	3,980	13,938
F2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ga	(6,534)	(7,952)	(9,131)	(23,617)	(10,093)	(11,511)	(12,472)	(34,076)	(13,132)	(13,578)	(14,717)	(41,428)	(16,245)	(17,189)	(75,416)	(108,849)
Gb	30.9%	30.1%	29.7%	30.2%	29.8%	28.9%	28.9%	29.2%	27.7%	26.8%	24.8%	26.4%	22.1%	20.3%	19.2%	20.5%
Ha	[redacted]															
Hb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hc	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H – J2	[redacted]															
K	7,407	7,935	8,138	23,481	8,185	8,664	8,691	25,540	9,025	9,588	10,752	29,365	12,332	13,168	13,932	39,432
La – Lb	[redacted]															

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) Forecasts of retail sales for the first five years of the forecast are reflective of PG&E's internal bundled retail sales forecast less interdepartmental (metered usage at PG&E-owned facilities) and GTSR sales.
Forecasts post-2020 use the most recent CPUC-approved bundled sales forecast filed in PG&E's 2014 Conformed Bundled Procurement Plan in AL 4750-E and approved June 15, 2016. This forecast does not subtract our interdepartmental and GTSR sales.

(2) (Row B) Assumes a linear trajectory for implementation of SB350 Compliance Period RPS targets post-2020 and three-year compliance periods after 2030.

(3) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2016 RPS Plan for a description of PG&E's VMOP.

(4) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(5) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(6) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(7) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear larger than they are in Rows Ha and J of the Alternative RNS, which shows the stochastically-adjusted Bank size.

(8) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(9) (Row Ia) The results in Ia are only applicable within the context of the stochastic model. Please see the Alternative RNS for the application of the bank.

(10) (Row Ib) As described in the Plan and Appendix J, PG&E is submitting a sales framework for CPUC approval.

(11) (Row K) Row K now includes only expiring volumes from contracts as of April 2016.

(12) (Rows La and Lb) Rows La and Lb incorrectly subtract the non-bankable volumes. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

(13) (Row Lb) Row Lb incorrectly calculates the Annual Net RPS Position after Bank Optimization. PG&E has changed the formula in the Alternative RNS to (Ga+Ia-Ib+E)/A in order to express these values in a comparable way to the Physical Net Short (%) in Row Gb.

APPENDIX C.2

Alternate Renewable Net Short Calculations

August 8, 2016

Table C.2: Alternate Renewable Net Short Calculation as of Apr 2016

Stochastically-Optimized Net Short Calculation Using PG&E Bundled Retail Sales Forecast and Corrections to Formulas

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Actuals	2016 Forecast	2014-2016	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024	2025 Forecast	2026 Forecast	2027 Forecast	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033	2034 Forecast	2035 Forecast	2036 Forecast	2034 - 2036
			Forecast Year	-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	CP4	-	-	-	CP5	-	-	-	CP6	-	-	-	CP7	-	-	-	CP8
			Annual RPS Requirement																																		
A			Bundled Retail Sales Forecast (Alternate)[1]	74,864	76,205	75,705	226,774	74,547	72,113	68,906	215,566	67,126	[redacted]		51,156	[redacted]	48,227	45,611	44,286	43,550	181,674	43,094	42,751	42,499	128,345	42,457	42,569	42,853	127,879	43,272	43,885	44,776	131,933	45,926	46,393	46,864	139,183
B			RPS Procurement Quantity Requirement (%)[2]	20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	34.8%	36.5%	38.3%	40.0%	37.4%	41.7%	43.3%	45.0%	43.3%	46.7%	48.3%	50.0%	48.3%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
C	A*B		Gross RPS Procurement Quantity Requirement (GWh)	14,973	15,241	15,141	45,355	16,177	16,802	17,227	50,206	18,124	[redacted]		16,881	[redacted]	16,759	16,648	16,939	17,420	67,766	17,970	18,511	19,125	55,606	19,827	20,561	21,427	61,815	21,636	21,942	22,388	65,966	22,963	23,196	23,432	69,591
D			Voluntary Margin of Over-procurement[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D		Net RPS Procurement Need (GWh)	14,973	15,241	15,141	45,355	16,177	16,802	17,227	50,206	18,124	[redacted]		16,881	[redacted]	16,759	16,648	16,939	17,420	67,766	17,970	18,511	19,125	55,606	19,827	20,561	21,427	61,815	21,636	21,942	22,388	65,966	22,963	23,196	23,432	69,591
			RPS-Eligible Procurement																																		
Fa			Risk-Adjusted RECs from Online Generation[4]	14,699	14,513	17,212	46,424	20,207	21,285	22,952	64,443	22,619	20,529	19,835	18,978	81,962	18,762	16,351	16,014	15,746	66,873	15,638	15,089	14,831	45,558	14,776	14,210	14,146	43,132	13,374	12,844	11,620	37,838	10,631	9,576	8,946	29,153
Faa			Forecast Failure Rate for Online Generation (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb			Risk-Adjusted RECs from RPS Facilities in Development[5]	-	-	-	-	-	-	84	84	833	1,048	1,938	2,006	5,825	2,045	2,034	2,023	2,017	8,119	2,002	1,992	1,982	5,976	1,975	1,961	1,951	5,887	1,941	1,901	1,867	5,709	1,209	1,201	1,133	3,543
Fbb			Forecast Failure Rate for RPS Facilities in Development (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc			Pre-Approved Generic RECs	-	-	-	-	-	-	-	-	44	433	846	1,002	2,325	1,006	1,004	1,003	1,003	4,016	999	997	996	2,992	996	992	990	2,979	989	989	985	2,964	984	982	983	2,948
Fd			Executed REC Sales	-	-	(142)	(142)	(50)	-	(60)	(110)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	Fa + Fb +Fc - Fd		Total RPS Eligible Procurement (GWh)[6]	14,699	14,513	17,069	46,281	20,157	21,285	22,976	64,418	23,496	22,010	22,619	21,986	90,112	21,813	19,390	19,040	18,766	79,008	18,640	18,078	17,808	54,526	17,747	17,163	17,087	51,997	16,303	15,735	14,473	46,511	12,823	11,759	11,062	35,645
F0			Category 0 RECs	14,651	13,049	14,163	41,863	16,899	17,409	18,200	52,509	18,006	15,980	15,255	14,400	63,641	13,983	11,596	11,301	11,077	47,957	10,999	10,460	10,216	31,676	10,166	9,635	9,589	29,390	8,891	8,792	8,168	25,850	7,537	7,088	7,082	21,707
F1			Category 1 RECs	48	1,464	2,906	4,418	3,257	3,875	4,776	11,908	5,490	6,030	7,364	7,586	26,470	7,830	7,793	7,739	7,689	31,051	7,641	7,618	7,592	22,850	7,581	7,529	7,498	22,607	7,412	6,943	6,305	20,661	5,286	4,671	3,980	13,938
F2			Category 2 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3			Category 3 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Step 1 Result: Physical Net Short[7]																																		
Ga	F-E		**Annual Gross RPS Position (GWh)**	(274)	(728)	1,928	926	3,980	4,482	5,750	14,212	5,372	[redacted]		5,105	[redacted]	5,054	2,741	2,101	1,346	11,242	669	(433)	(1,317)	(1,080)	(2,080)	(3,398)	(4,340)	(9,817)	(5,333)	(6,208)	(7,915)	(19,456)	(10,140)	(11,437)	(12,370)	(33,946)
Gb	F/A		**Annual Gross RPS Position (%)**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	33.3%	29.9%	35.0%	[redacted]		43.0%	[redacted]	45.2%	42.5%	43.0%	43.1%	43.5%	43.3%	42.3%	41.9%	42.5%	41.8%	40.3%	39.9%	40.7%	37.7%	35.9%	32.3%	35.3%	27.9%	25.3%	23.6%	25.6%

PG&E's Alternative RNS Table - Stochastic-Adjustment (2011-2033)[8]

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013 Actuals	2014 Actuals	2015 Actuals	2016 Forecast	2014-2016	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024	2025 Forecast	2026 Forecast	2027 Forecast	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033
[redacted]																																	
			Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short + Stochastic Risk-Adjustment)[9]																														
Gd			**Stochastically-Adjusted Annual Gross RPS Position (GWh)**	(274)	(728)	1,928	926	3,980	4,482	[redacted]																							
Ge			**Stochastically-Adjusted Annual Gross RPS Position (%)**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	[redacted]																							
			Application of Bank																														
Ha	H - Hc (from previous year)	J - Hc (from previous year)	Existing Banked RECs above the PQR (The Bank at Beg. Of Period)[10,11]	-	-	-	-	861	4,815	[redacted]	861	[redacted]																					
Hb			RECs above the PQR added to Bank	(274)	(728)	1,928	926	[redacted]																									
Hc			Non-bankable RECs above the PQR	-	31	34	65	26	25	27	78	94	-	-	-	94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Ha+Hb		Gross Balance of RECs above the PQR	(274)	(728)	1,928	926	[redacted]																									
Ia			Planned Application of RECs above the PQR towards RPS Compliance	-	-	-	-	[redacted]																									
Ib			Planned Sales of RECs above the PQR[12]	-	-	-	-	[redacted]																									
J	H-Ia-Ib		Net Balance of RECs above the PQR (The Bank at End of Period)[10]	(274)	(728)	1,928	926	[redacted]																									
J0			Category 0 RECs	-	-	-	-	[redacted]																									
J1			Category 1 RECs	(274)	(728)	1,928	926	[redacted]																									
J2			Category 2 RECs	-	-	-	-	[redacted]																									
			Expiring Contracts																														
K			RECs from Expiring RPS Contracts[13]	N/A	N/A	N/A	N/A	N/A	N/A	17	17	396	2,552	3,245	4,109	10,301	4,449	6,811	7,105	7,381	25,745	7,407	7,935	8,138	23,481	8,185	8,664	8,691	25,540	9,588	10,752	12,332	32,671
			Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank)[14]																														
La	Ga+Ia-Ib-Hc	Gd+Ia-Ib	**Annual Net RPS Position after Bank Optimization (GWh)**	(274)	(728)	1,928	926	[redacted]																									
Lb	(F+Ia-Ib-Hc)/A	(Gd+Ia-Ib+E)/A	**Annual Net RPS Position after Bank Optimization (%)**	19.6%	19.0%	22.5%	20.4%	[redacted]																									

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) PG&E uses its April 2016 internal bundled retail sales forecast for its procurement decisions.†

(2) (Row B) Assumes a linear trajectory for implementation of SB350 Compliance Period RPS targets post-2020 and three-year compliance periods after 2030.

(3) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See 2016 RPS Plan for a description of PG&E's VMOP.

(4) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(5) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(6) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(7) (Step 1 Result: Physical Net Short) Rows Ga and Gb represent PG&E's physical net short based on PG&E's internal bundled retail sales forecast, as opposed to the LTPP forecast provided in Table C.1.

(8) The stochastic model optimizes procurement from 2023 to 2033.

(9) (Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short+ Stochastic Risk-Adjustment) PG&E added rows Gd and Ge to the Alternative RNS in order to show the stochastically-adjusted physical net short, which incorporates the risks and uncertainties addressed in the stochastic model. For more details on PG&E's stochastically modeled risks, see the 2016 RPS Plan. This is prior to any application of the Bank.

(10) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear smaller than they are in Rows Ha and J of the RNS, which shows the non-stochastically-adjusted Bank size.

(11) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(12) (Row Ib) As described in the Plan and Appendix J, PG&E is submitting a sales framework for CPUC approval.

(13) (Row K) Row K now includes only expiring volumes from contracts as of April 2016.

(14) (Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank))

(a) Rows La and Lb represent the optimized net short that results from taking Row Gd (Step 2 Result) and then applying Bank usage. Bank can be used for either (i) compliance purposes (row Ia) or (ii) sales (Row Ib).

(b) Row La in the Alternative RNS does not match Row La in the RNS, because the RNS does not include Row Gd (Stochastically-Adjusted Net Short).

(c) PG&E includes the non-bankable volumes in calculating rows La and Lb. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

*Stochastic Results in Rows Gd-Lb reflect a April 2016 stochastic modeling vintage.

APPENDIX D

Procurement Information Related to Cost Quantification

August 8, 2016

Appendix D – Procurement Information Related to Cost Quantification

Assumptions	
Table 1 (Actual Costs, $) Items	**Actual**
Rows 2 -- 8, 11 (2003-2015)[1,2,3,4,5]	Settled contract costs with all RPS-eligible contracts in PG&E's portfolio for 2003-2015
Row 9	For 2003-2011, capital costs are based on the net book value of PG&E's RPS-eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14%. For 2012 through 2015, capital costs are based on the net book value of PG&E's RPS-eligible units as of December of that respective year multiplied by a fixed charge rate of 14%. PG&E's actual operation and maintenance (O&M) costs for each year (2003-2015) were added to each year's capital costs to calculate total costs.
Row 10	LCOE for each project multiplied by the project's historical generation
Row 13	PG&E actual bundled retail sales
Row 14	Total Cost / Bundled Retail Sales (Row 12 / Row 13)
Table 2 (Forecast Costs, $) Items	**Forecast**
Rows 2 -- 8, 11, 16 -- 22, 25[6]	PG&E's future expenditures on all RPS-eligible procurement and generation approved to date. 2016-2030 forecast uses April 2016 vintage contract data. January-April 2016 uses December 2015 vintage forward price curve data. May 2016-2030 uses April 2016 forward price curve data. May 2016 - 2017 forecast data are consistent with the 2017 ERRA forecast filing.
Rows 9 and 23	For 2016-2030, annualized capital costs based on the net book value of PG&E's RPS-eligible units as of December 2015 were added to operation and maintenance (O&M) costs, which were calculated as 2015 O&M costs escalated at 5% annually for each year.
Row 10 and 24	LCOE for each project multiplied by the project's forecasted generation
Rows 13 and 27	PG&E bundled retail sales forecast
Rows 14 and 28	Total Cost / Bundled Sales
Row 29	Row 14 + Row 28
Table 3 (Actual Generation, MWh) Items	**Actual**
Rows 2 -- 11[1,3,4,5,6]	Generation (MWh) associated with payments for RPS-eligible deliveries
Table 4 (Forecast Generation, MWh) Items	**Forecast**
Rows 2 -- 11 and 16-25	Forecasted RPS-eligible generation (MWh) either (1) approved to date or (2) executed prior to April 2016 but pending Commission approval -- assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. 2016-2030 uses April 2016 contract vintage.

1 2015 Generation and Costs were updated to reflect best available data as of April 2016.

2 Row 5 includes the aggregate costs (specifically debt service and operation and maintenance) of PG&E's contract with Solano Irrigation District (SID) who supplies power from multiple hydro units, 100% of which are RPS-eligible. Yuba County Water Agency (YCWA) does not operate any RPS-eligible hydro units, therefore YCWA cost data is not relevant and thereby not included.

3 RPS-eligible generation reported in 2015 is the best available settlements data as of April 2016. Settlements data for the prior year can continue to be adjusted after January of the current year.

4 Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.

5 Cost for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology specific costs based on the technology specific generation (MWh) of the sale contract.

6 UOG Small Hydro generation for 2013-2015 has been updated to reflect actual settlements data.

Note: As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 1
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs												
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
2	Biogas	$25,762	$23,856	$25,623	$22,823	$24,126	$23,468	$27,306	$20,216	$16,776	$5,333	$5,063	$11,087	$22,283
3	Biomass	$215,078	$217,923	$217,279	$222,125	$238,524	$259,957	$262,086	$263,994	$245,622	$302,711	$299,205	$317,301	$286,766
4	Geothermal	$110,572	$111,778	$108,720	$118,523	$199,143	$282,227	$200,357	$260,053	$223,575	$209,854	$284,334	$324,050	$280,843
5	Small Hydro	$60,984	$57,470	$80,340	$97,340	$63,161	$72,488	$52,053	$63,296	$84,864	$54,140	$57,213	$45,522	$34,247
6	Solar PV	$0	$0	$0	$0	$0	$0	$2,554	$10,180	$33,370	$176,372	$504,860	$803,806	$949,556
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,698	$173,856	$296,915
8	Wind	$65,244	$74,912	$56,891	$67,116	$98,203	$102,516	$199,475	$224,089	$340,517	$379,416	$424,764	$437,159	$422,102
9	UOG Small Hydro	$44,936	$45,059	$46,526	$47,556	$47,933	$49,009	$47,567	$49,684	$52,099	$51,572	$64,691	$66,066	$74,770
10	UOG Solar	$0	$0	$0	$0	$227	$452	$473	$1,498	$5,620	$27,093	$43,882	$52,426	$49,535
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$823	$871	$677	$805	$704.86
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$522,576**	**$530,998**	**$535,380**	**$575,483**	**$671,317**	**$790,116**	**$791,870**	**$893,010**	**$1,003,268**	**$1,207,361**	**$1,686,387**	**$2,232,077**	**$2,417,720**
13	Bundled Retail Sales [Thousands of kWh]	71,099,363	72,113,608	72,371,532	76,356,279	79,078,319	81,523,859	79,624,479	77,485,129	74,863,941	76,205,120	75,705,039	74,546,865	72,112,848
14	**Incremental Rate Impact**[2]	**0.73 ¢/kWh**	**0.74 ¢/kWh**	**0.74 ¢/kWh**	**0.75 ¢/kWh**	**0.85 ¢/kWh**	**0.97 ¢/kWh**	**0.99 ¢/kWh**	**1.15 ¢/kWh**	**1.34 ¢/kWh**	**1.58 ¢/kWh**	**2.23 ¢/kWh**	**2.99 ¢/kWh**	**3.35 ¢/kWh**

1 The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row. For example, the cost of an Unbundled REC procured from a wind facility is only reported in the Unbundled RECs row.

2 Incremental Rate Impact is equal to Row 12 divided by Row 13. While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs				
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$0**	**$0**	**$0**	**$0**	**$0**
13	Bundled Retail Sales [Thousands of kWh]	68,906,299	67,126,317	[redacted]	[redacted]	51,155,993
14	**Incremental Rate Impact[2]**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	$27,720	$30,066	$29,854	$29,872	$30,064
17	Biomass	$273,857	$249,580	$218,487	$195,821	$140,950
18	Geothermal	$283,645	$289,770	$179,115	$180,105	$182,193
19	Small Hydro	$68,801	$63,191	$55,056	$52,168	$47,629
20	Solar PV	$910,489	$956,374	$978,708	$1,043,925	$1,051,761
21	Solar Thermal	$327,058	$326,270	$325,944	$325,865	$327,539
22	Wind	$429,794	$427,906	$425,240	$408,982	$409,878
23	UOG Small Hydro	$76,353	$78,016	$79,762	$81,595	$83,520
24	UOG Solar	$51,288	$51,022	$50,757	$50,494	$50,232
25	Unbundled RECs[1]	$0	$0	$0	$0	$0
26	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25]	**$2,449,005**	**$2,472,193**	**$2,342,923**	**$2,368,828**	**$2,323,765**
27	Bundled Retail Sales [Thousands of kWh]	68,906,299	67,126,317	[redacted]	[redacted]	51,155,993
28	**Incremental Rate Impact[2]**	**3.55 ¢/kWh**	**3.68 ¢/kWh**	[redacted]	[redacted]	**4.54 ¢/kWh**
29	**Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]	**3.55 ¢/kWh**	**3.68 ¢/kWh**	[redacted]	[redacted]	**4.54 ¢/kWh**

1 See footnote 1 from Table 1.

Appendix D – Procurement Information Related to Cost Quantification

[2] Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs									
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
13	Bundled Retail Sales [Thousands of kWh]	48,226,979	45,611,218	44,285,751	43,549,939	43,094,448	42,750,940	42,499,122	42,456,543	42,569,098	42,853,116
14	**Incremental Rate Impact[2]**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
16	Biogas	$30,025	$30,131	$30,144	$29,837	$29,407	$29,113	$29,173	$29,294	$27,196	$26,884
17	Biomass	$132,619	$133,591	$134,548	$135,832	$136,568	$137,398	$105,902	$101,186	$101,224	$101,525
18	Geothermal	$181,802	$13,563	$13,470	$13,423	$13,314	$13,256	$13,174	$13,121	$12,997	$12,921
19	Small Hydro	$36,595	$30,605	$29,833	$30,102	$29,802	$30,151	$30,533	$30,607	$25,575	$25,294
20	Solar PV	$1,048,293	$1,045,504	$1,041,549	$1,039,756	$1,036,757	$1,037,632	$1,033,899	$1,032,206	$1,024,188	$1,020,698
21	Solar Thermal	$326,648	$326,616	$326,270	$326,334	$326,167	$327,075	$326,648	$326,738	$325,944	$325,865
22	Wind	$403,498	$397,741	$378,189	$353,898	$351,826	$287,184	$287,389	$288,103	$251,668	$251,001
23	UOG Small Hydro	$85,541	$87,663	$89,891	$92,230	$94,687	$97,266	$99,975	$102,819	$105,805	$108,940
24	UOG Solar	$49,972	$49,712	$49,455	$49,198	$48,943	$48,689	$48,437	$48,185	$47,935	$47,687
25	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25]	**$2,294,992**	**$2,115,126**	**$2,093,348**	**$2,070,610**	**$2,067,470**	**$2,007,764**	**$1,975,129**	**$1,972,259**	**$1,922,533**	**$1,920,815**
27	Bundled Retail Sales [Thousands of kWh]	48,226,979	45,611,218	44,285,751	43,549,939	43,094,448	42,750,940	42,499,122	42,456,543	42,569,098	42,853,116
28	**Incremental Rate Impact[2]**	**4.76 ¢/kWh**	**4.64 ¢/kWh**	**4.73 ¢/kWh**	**4.75 ¢/kWh**	**4.80 ¢/kWh**	**4.70 ¢/kWh**	**4.65 ¢/kWh**	**4.65 ¢/kWh**	**4.52 ¢/kWh**	**4.48 ¢/kWh**
29	**Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]	**4.76 ¢/kWh**	**4.64 ¢/kWh**	**4.73 ¢/kWh**	**4.75 ¢/kWh**	**4.80 ¢/kWh**	**4.70 ¢/kWh**	**4.65 ¢/kWh**	**4.65 ¢/kWh**	**4.52 ¢/kWh**	**4.48 ¢/kWh**

1 See footnote 1 from Table 1.

2 Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 3
(Actual Generation, MWh)

		Actual RPS-Eligible Procurement and Generation (MWh)												
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
2	Biogas	364,745	333,897	366,514	300,943	293,147	280,795	342,362	306,909	284,129	112,153	85,706	112,161	212,975
3	Biomass	2,839,795	2,961,633	2,858,643	2,770,398	2,751,813	2,813,819	3,122,048	2,990,615	3,043,656	3,158,131	3,055,370	3,226,904	2,814,468
4	Geothermal	1,674,702	1,753,043	1,687,360	1,790,870	2,701,970	3,350,232	3,411,798	3,766,700	3,780,954	3,807,728	3,687,236	3,870,952	3,646,936
5	Small Hydro	1,269,233	1,096,183	1,457,339	1,760,707	927,879	945,921	937,626	1,092,707	1,457,714	863,606	652,953	400,300	304,368
6	Solar PV	6	4	4	3	1	1	21,706	58,593	179,171	1,006,145	3,358,366	5,266,030	6,260,429
7	Solar Thermal	0	0	0	0	0	0	0	0	0	0	20,581	878,905	1,557,412
8	Wind	940,239	1,078,579	874,204	1,019,451	1,374,337	1,439,796	2,557,988	2,981,660	4,395,377	4,515,452	4,924,052	5,358,546	5,418,594
9	UOG Small Hydro	1,382,934	1,267,084	1,403,130	1,437,196	984,607	993,266	1,103,017	1,157,077	1,254,638	948,734	929,639	580,990	537,838
10	UOG Solar	0	0	0	0	225	445	504	4,642	26,790	165,656	279,500	336,905	318,582
11	Unbundled RECs[2]	0	0	0	0	0	0	0	0	102,888	108,874	101,256	100,581	88,107
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11]	8,471,654	8,490,423	8,647,195	9,079,568	9,033,979	9,824,276	11,497,048	12,358,903	14,525,317	14,686,479	17,094,659	20,132,274	21,159,709

[1] Energy Volumes reported for 2015 in Rows 2 – 11 are the best available settlements data as of April 2016.

[2] Row 11 only includes Unbundled RECs with CPUC approval.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 4
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries 2015-2020 (MWh)				
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	0	0	0	0	0
3	Biomass	0	0	0	0	0
4	Geothermal	0	0	0	0	0
5	Small Hydro	0	0	0	0	0
6	Solar PV	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0
8	Wind	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0
10	UOG Solar	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11]	0	0	0	0	0
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	251,523	266,995	266,993	266,306	266,360
17	Biomass	2,901,274	2,734,501	2,415,737	2,044,887	1,306,885
18	Geothermal	3,846,522	3,835,023	2,319,523	2,318,615	2,324,132
19	Small Hydro	1,027,686	918,985	799,965	728,760	626,492
20	Solar PV	6,261,500	6,927,812	7,271,865	8,119,786	8,160,001
21	Solar Thermal	1,765,243	1,762,261	1,762,261	1,762,261	1,765,243
22	Wind	5,448,391	5,383,493	5,327,732	5,122,748	5,121,450
23	UOG Small Hydro	1,528,272	1,334,249	1,563,122	1,498,509	1,482,998
24	UOG Solar	329,769	328,054	326,347	324,649	322,961
25	Unbundled RECs	0	0	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25]	23,360,181	23,491,374	22,053,545	22,186,523	21,376,523

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 4 (continued)
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries 2021-2030 (MWh)									
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	0	0	0	0	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0	0	0	0	0
4	Geothermal	0	0	0	0	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0	0	0	0	0
6	Solar PV	0	0	0	0	0	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0	0	0	0	0	0
8	Wind	0	0	0	0	0	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0	0	0	0	0	0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11]	0	0	0	0	0	0	0	0	0	0
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
16	Biogas	265,082	265,094	264,638	261,585	256,076	251,715	251,667	252,358	240,635	238,453
17	Biomass	1,179,300	1,179,327	1,179,385	1,182,006	1,179,336	1,176,297	971,733	941,134	938,989	938,941
18	Geothermal	2,316,815	152,229	151,342	150,941	149,584	148,713	147,846	147,454	146,129	145,278
19	Small Hydro	510,274	424,593	403,033	402,568	394,368	394,630	393,599	389,557	343,507	337,029
20	Solar PV	8,144,627	8,093,027	8,042,037	8,007,968	7,941,083	7,891,114	7,841,481	7,808,341	7,724,848	7,669,709
21	Solar Thermal	1,762,261	1,762,261	1,762,261	1,765,243	1,762,261	1,762,261	1,762,261	1,765,243	1,762,261	1,762,261
22	Wind	4,997,701	4,883,296	4,609,823	4,358,250	4,326,117	3,808,664	3,808,664	3,816,232	3,392,738	3,382,295
23	UOG Small Hydro	1,473,170	1,468,853	1,470,226	1,471,744	1,467,274	1,468,960	1,465,995	1,469,606	1,463,822	1,467,788
24	UOG Solar	321,281	319,609	317,947	316,293	314,648	313,011	311,384	309,764	308,153	306,551
25	Unbundled RECs	0	0	0	0	0	0	0	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25]	20,970,511	18,548,288	18,200,691	17,916,598	17,790,746	17,215,364	16,954,629	16,899,690	16,321,083	16,248,304

APPENDIX E

RPS-Eligible Contracts Expiring 2016-2026

August 8, 2016

Appendix E - RPS Eligible Contracts Expiring 2016-2026

Log Number	Project Name	Facility Name	Contract Expiration Year	Contract Capacity MW	Expected Annual Generation (GWh)	Contract Type	Resource Type	City	State
01W146C	Green Ridge Power (100 MW - C)	Green Ridge Power LLC (100 MW - C)	2018	11.9	n/a	Qualifying Facility (QF)	Wind	Tracy	CA
04H011	Far West Power Corporation	Far West Power Corporation	2017	0.4	n/a	Qualifying Facility (QF)	Hydro: Small	Potter Valley	CA
04P010	Gas Recovery Sys. (American Cyn)	American Canyon	2016	1.5	n/a	Qualifying Facility (QF)	Biogas Generation	AMERICAN CANYON	CA
06H011	Rock Creek	Rock Creek L.P.	2016	3	n/a	Qualifying Facility (QF)	Hydro: Small	Placerville	CA
06H011QPA	Rock Creek Hydro	Rock Creek Hydro Project	2016	2.796	6.324	QF/CHP Summit	Hydro: Small	Placerville	CA
06W146B	EDF Renewable Windfarm V, Inc. (70 MW - B)	EDF Renewable Windfarm V, Inc. (70 MW - B)	2017	0.7	n/a	Qualifying Facility (QF)	Wind	Suisun City	CA
06W146C	EDF Renewable Windfarm V, Inc. (70 MW - C)	EDF Renewable Windfarm V, Inc. (70 MW - C)	2018	6.5	n/a	Qualifying Facility (QF)	Wind	Suisun City	CA
06W146D	EDF Renewable Windfarm V, Inc. (70 MW - D)	EDF Renewable Windfarm V, Inc. (70 MW - D)	2018	1.5	n/a	Qualifying Facility (QF)	Wind	Suisun City	CA
06W148	EDF Renewable Windfarm V, Inc. (10 MW)	EDF Renewable Windfarm V, Inc. (10 MW)	2017	10	n/a	Qualifying Facility (QF)	Wind	Suisun City	CA
08C078	City of Watsonville	City Of Watsonville	2023	0.55	n/a	Qualifying Facility (QF)	Biogas Generation	Watsonville	CA
08C080	Santa Cruz WWTP	Santa Cruz WWTP	2021	0.65	n/a	Qualifying Facility (QF)	Biogas Generation	Santa Cruz	CA
08H013	Santa Clara Valley Water Dist.	Santa Clara Valley Water Dist.	2018	0.8	n/a	Qualifying Facility (QF)	Hydro: Small	MORGAN HILL	CA
10C003	Collins Pine	Collins Pine	2016	12	n/a	Qualifying Facility (QF)	Biomass	CHESTER	CA
10C009	Sierra Pacific Ind. (Susanville)	Sierra Pacific Ind.(Susanville)	2016	15	n/a	Qualifying Facility (QF)	Biomass	Susanville	CA
10C010	Sierra Pacific Ind. (Sonora)	Sierra Pacific Ind.(Sonora)	2016	7.5	n/a	Qualifying Facility (QF)	Biomass	Sonora	CA
10C018	Sierra Pacific Ind. (Quincy)	Sierra Pacific Ind. (Quincy)	2017	20	n/a	Qualifying Facility (QF)	Biomass	QUINCY	CA
10G012QPA	Amedee Geothermal Venture 1	Amedee Geothermal Venture 1	2016	0.69	3.5	QF/CHP Summit	Geothermal	Wendel	CA
10H002	Lassen Station Hydro	Lassen Station Hydro	2016	0.99	n/a	Qualifying Facility (QF)	Hydro: Small	Oroville	CA
10H010	Five Bears Hydroelectric	Five Bears Hydroelectric	2019	0.99	n/a	Qualifying Facility (QF)	Hydro: Small	Genesee Valley	CA
10H013	Hypower, Inc.	Hypower, Inc.	2022	10.8	n/a	Qualifying Facility (QF)	Hydro: Small	De Sabla	CA
10P005	HL Power	HL Power	2019	32	n/a	Qualifying Facility (QF)	Biomass	Wendel	CA
12C008	Sierra Pacific Ind. (Lincoln)	Sierra Pacific Ind. (Lincoln)	2017	7.5	n/a	Qualifying Facility (QF)	Biomass	LINCOLN	CA
12H006	Yuba County Water Agency (Fish Release)	Yuba County Water Agency (Fish Release)	2016	0.15	n/a	Qualifying Facility (QF)	Hydro: Small	Dobbins	CA
12H007	STS Hydropower (Kanaka)	STS Hydropower Ltd. (Kanaka)	2019	1.1	n/a	Qualifying Facility (QF)	Hydro: Small	Oroville	CA
12H010	Deadwood Creek	Deadwood Creek (Yuba County Water Agency)	2020	2	n/a	Qualifying Facility (QF)	Hydro: Small	CHALLENGE	CA
12P001	Pacific Oroville Power	Ogden Power Pacific, Inc. (Oroville)	2016	18	n/a	Qualifying Facility (QF)	Biomass	OROVILLE	CA
13C038	Burney Forest Products	Burney Facility	2020	31	n/a	Qualifying Facility (QF)	Biomass	Burney	CA
13C049	Sierra Pacific Ind. (Burney)	Sierra Pacific Ind. (Burney)	2016	20	n/a	Qualifying Facility (QF)	Biomass	Burney	CA
13H001	El Dorado Hydro (Montgomery Creek)	El Dorado Irrigation District	2017	2.6	n/a	Qualifying Facility (QF)	Hydro: Small	Pollock Pines	CA
13H008	Arbuckle Mountain Hydro	Arbuckle Mountain Hydro	2016	0	n/a	Qualifying Facility (QF)	Hydro: Small	Platina	CA
13H013	Snow Mountain Hydro (Cove)	Snow Mountain Hydro (Cove)	2020	5	n/a	Qualifying Facility (QF)	Hydro: Small	MONTGOMERY CREEK	CA
13H014	Mega Renewables (Roaring Crk)	Roaring Crk	2016	2	n/a	Qualifying Facility (QF)	Hydro: Small	MONTGOMERY CREEK	CA
13H015	Mega Renewables (Hatchet Crk)	Hatchet Crk	2017	7	n/a	Qualifying Facility (QF)	Hydro: Small	MONTGOMERY CREEK	CA
13H016	Snow Mountain Hydro (Burney Creek)	Burney Creek - Amendment	2020	3	n/a	Qualifying Facility (QF)	Hydro: Small	Burney	CA
13H017	Mega Renewables (Bidwell Ditch)	Bidwell Ditch	2017	2	n/a	Qualifying Facility (QF)	Hydro: Small	Burney	CA
13H024	Olsen Power Partners	Olsen Power Partners	2019	5	n/a	Qualifying Facility (QF)	Hydro: Small	Whitmore	CA
13H035	Snow Mountain Hydro (Ponderosa Bailey Creek)	Snow Mountain Hydro (Ponderosa Bailey Creek)	2020	1.1	n/a	Qualifying Facility (QF)	Hydro: Small	Manton	CA
13H036	Mega Renewables (Silver Springs)	Silver Springs	2017	0.6	n/a	Qualifying Facility (QF)	Hydro: Small	Big Bend	CA
13H039QPA	STS Hydropower (Kekawaka)	Kekawaka Creek Hydroelectric Facility	2019	5.445	16	QF/CHP Summit	Hydro: Small	Alderpoint	CA
13H040	TKO Power - South Fork Bear Creek	South Fork Bear Creek	2016	3	n/a	Qualifying Facility (QF)	Hydro: Small	SHINGLETOWN	CA
13H040QPA	TKO Power - South Fork Bear Creek	South Fork Bear Creek	2016	3	8.352	QF/CHP Summit	Hydro: Small	SHINGLETOWN	CA
13H042	Nelson Creek Power Inc.	Nelson Creek Power Inc.	2018	1.1	n/a	Qualifying Facility (QF)	Hydro: Small	Big Bend	CA
13H125	Mega Hydro #1 (Clover Creek)	Clover Creek	2016	1	n/a	Qualifying Facility (QF)	Hydro: Small	OAK RUN	CA
13H125QPA	Hydro Partners (Clover Creek)	Clover Creek	2018	0.999	7.5	QF/CHP Summit	Hydro: Small	OAK RUN	CA
13P045	Wheelabrator Shasta	Wheelabrator Shasta	2018	54.9	n/a	Qualifying Facility (QF)	Biomass	Anderson	CA
13P163EO2	Sierra Pacific Ind. (Anderson)	Anderson 1 Facility	2016	5	5	Qualifying Facility (QF)	Biomass	Anderson	CA
15H005	EIF Haypress (Lwr)	Haypress Hydroelectric, Inc. (LWR)	2019	6.1	n/a	Qualifying Facility (QF)	Hydro: Small	Sierra City	CA
15H006	EIF Haypress (Mdl)	Haypress Hydroelectric, Inc. (MDL)	2019	8.7	n/a	Qualifying Facility (QF)	Hydro: Small	Sierra City	CA
15H013	NID/Combie North	Combie North Powerhouse	2018	0.33	n/a	Qualifying Facility (QF)	Hydro: Small	Grass Valley	CA
15H015	Nevada Irrigation District/Bowman	Bowman Powerhouse	2016	3.6	n/a	Qualifying Facility (QF)	Hydro: Small	Nevada City	CA
15H032	Martin Teeling	Martin Teeling	2026	0.3	n/a	Qualifying Facility (QF)	Hydro: Small	Camptonville	CA
15P028	Rio Bravo Rocklin	Rocklin Facility	2020	25	n/a	Qualifying Facility (QF)	Biomass	ROCKLIN	CA
16H003	Tri-Dam Authority	Tri-Dam Authority	2016	16.2	n/a	Qualifying Facility (QF)	Hydro: Small	Strawberry	CA
16P002	Pacific-Ultrapower Chinese Station	Ogden Power Pacific, Inc. (Chinese Station)	2017	22	n/a	Qualifying Facility (QF)	Biomass	Jamestown	CA
16P054	Thermal Energy Dev. Corp.	Thermal Energy Dev. Corp.	2020	21	n/a	Qualifying Facility (QF)	Biomass	Tracy	CA
16W011A	Cogeneration Capital Association	Cogeneration Capital Association	2017	2.68	n/a	Qualifying Facility (QF)	Wind	Tracy	CA
16W017	Altamont Power (6-4)	Altamont Power LLC (6-4)	2016	19	n/a	Qualifying Facility (QF)	Wind	Tracy	CA

Appendix E - RPS Eligible Contracts Expiring 2016-2026

Log Number	Project Name	Facility Name	Contract Expiration Year	Contract Capacity MW	Expected Annual Generation (GWh)	Contract Type	Resource Type	City	State
16W173	Cogen Capital (Altamont Power)	Cogen Capital (Altamont Power)	2017	2.68	n/a	Qualifying Facility (QF)	Wind	Tracy	CA
18H054	City of San Luis Obispo	City Of San Luis Obispo	2025	0.782	n/a	Qualifying Facility (QF)	Hydro: Small	SAN LUIS OBISPO	CA
19P005	DG Fairhaven Power	DG Fairhaven Power, LLC	2017	17.25	n/a	Qualifying Facility (QF)	Biomass	FAIRHAVEN	CA
25H040	Madera Canal (1174 + 84)	Madera Canal (1174 + 84)	2016	0.563	n/a	Qualifying Facility (QF)	Hydro: Small	Madera	CA
25H041	Madera Canal Station 1302	Madera Canal Station 1302	2016	0.424	n/a	Qualifying Facility (QF)	Hydro: Small	Madera	CA
25H042	Madera Canal (1923)	Madera Canal (1923)	2016	0.916	n/a	Qualifying Facility (QF)	Hydro: Small	Madera	CA
25H073	Olcese Water District	Kern Hydro (Olcese)	2019	16	n/a	Qualifying Facility (QF)	Hydro: Small	Bakersfield	CA
25H149	Orange Cove Irrigation Dist.	Orange Cove Irrigation Dist.	2020	0.45	n/a	Qualifying Facility (QF)	Hydro: Small	Friant	CA
25H150	Kings River Hydro Co.	Kings River Hydro	2020	1	n/a	Qualifying Facility (QF)	Hydro: Small	Sanger	CA
25P026	Rio Bravo Fresno	Rio Bravo Fresno	2019	26.5	n/a	Qualifying Facility (QF)	Biomass	Fresno	CA
25W105	International Turbine Research	International Turbine Research	2018	34	n/a	Qualifying Facility (QF)	Wind	PACHECO PASS	CA
33R009	Diablo Winds	Diablo Winds	2016	18	65	RPS	Wind	Livermore	CA
33R012	Buena Vista Wind Project	Buena Vista Energy	2017	43	108	RPS	Wind	Byron	CA
33R015	Shiloh I Wind Project	Shiloh I Wind	2021	75	225	RPS	Wind	Birds Landing	CA
33R026	Eden Vale Dairy	Eden Vale Dairy	2021	0.15	1.314	RPS	Biogas Generation	Lemoore	CA
33R030	Klondike Wind Power Project III	Klondike III Wind Power	2022	85	265	RPS	Wind	Wasco	OR
33R038	Wadham Energy LP	Wadham	2018	26.5	141	RPS	Biomass	Williams	CA
33R045	Rattlesnake Road Wind Power Project	Arlington Wind Power Project - Rattlesnake Road	2024	102.9	240	RPS	Wind	Arlington	OR
33R053AB	Santa Maria II	Santa Maria II LFG Power Plant	2025	1.42	12.439	AB1969/FiT	Biogas Generation	Santa Maria	CA
33R054	Klondike IIIA	Klondike IIIA Wind Power	2019	90	263.258	RPS	Wind	Wasco	OR
33R058	Hatchet Ridge	Hatchet Ridge Wind	2025	103.2	303	RPS	Wind	Burney	CA
33R061AB	Castelanelli Bros. Biogas	Castelanelli Bros.	2019	0.3	1.3	AB1969/FiT	Biogas Generation	Lodi	CA
33R074	SFWP - Sly Creek / Kelly Ridge	Multiple	2020	23	106	RPS	Hydro: Small	Multiple	Multiple
33R075	Woodland Biomass	Woodland Biomass	2020	25	175	RPS	Biomass	Woodland	CA
33R076AB	Ortigalita Power Company	Ortigalita Power Company	2026	0.75	5.585	AB1969/FiT	Biomass	Merced	CA
33R077AB	Combie North	Combie North Powerhouse	2024	0.5	1.316	AB1969/FiT	Hydro: Small	Grass Valley	CA
33R081	Big Valley Power	Big Valley Power	2019	7.5	40	RPS	Biomass	Bieber	CA
33R083	Vantage Wind Energy Center	Vantage Wind Energy Center	2025	90	277	RPS	Wind	Ellensburg	WA
33R093	Geysers	Multiple	2021	425	3537	RPS	Geothermal	Multiple	Multiple
33R096AB	Combie South	Combie South Powerhouse	2020	1.5	3.947	AB1969/FiT	Hydro: Small	Grass Valley	CA
33R101AB	Snow Mountain Hydro (Lost Creek 1)	Lost Creek 1	2019	1.1	9.636	AB1969/FiT	Hydro: Small	Hat Creek	CA
33R102AB	Snow Mountain Hydro (Lost Creek 2)	Lost Creek 2	2019	0.5	4.38	AB1969/FiT	Hydro: Small	Hat Creek	CA
33R139AB	Vecino Vineyards	Vecino Vineyards Hydroelectric Plant	2026	0.33	0.1	AB1969/FiT	Hydro: Small	Potter Valley	CA
33R140	El Dorado Irrigation District	Multiple	2021	22	99.3	RPS	Hydro: Small	Multiple	Multiple
33R141AB	NID Scotts Flat	Scotts Flat Powerhouse	2020	0.85	3.203	AB1969/FiT	Hydro: Small	Nevada City	CA
33R146AB	Blake's Landing	80kW Generator	2020	0.08	0.6	AB1969/FiT	Biogas Generation	Marshall	CA
33R230AB	Wolfsen Bypass	Wolfsen Bypass	2022	0.98	5	AB1969/FiT	Hydro: Small	Los Banos	CA
33R231AB	San Luis Bypass	San Luis Bypass	2022	0.6	3	AB1969/FiT	Hydro: Small	LOS BANOS	CA
33R240AB	South Sutter Water	Vanjop No. 1	2022	0.395	2	AB1969/FiT	Hydro: Small	Sheridan	CA
33R246	Wind Resource I	Wind Resource I	2022	8.71	15.41	RPS	Wind	Tehachapi	CA
33R250AB	Browns Valley Irrigation District	Virginia Ranch Dam Powerhouse	2022	1.04	5.2	AB1969/FiT	Hydro: Small	Oregon House	CA
33R252	PCWA (French Meadows, Oxbow, Hell Hole)	Multiple	2017	24.6	93	RPS	Hydro: Small	Multiple	Multiple
33R276	Wind Resource II	Wind Resource II (1)	2023	19.955	46.41	RPS	Wind	Tehachapi	CA
33R284	ABEC Bidart-Stockdale	Bidart Dairy III (Stockdale)	2023	0.6	1.4	RPS	Biogas Generation	Bakersfield	CA
33R333RM	Digger Creek Hydro	Digger Creek Hydro	2024	0.65	3.5	SB32/ReMAT	Hydro: Small	Manton	CA
33R337RM	Clover Flat LFG	Clover Flat LFG	2024	0.848	5.747	SB32/ReMAT	Biogas Generation	Calistoga	CA
33R342RM	Water Wheel Ranch	Water Wheel Ranch (SB32)	2025	0.975	3.88	SB32/ReMAT	Hydro: Small	Round Mountain	CA
33R352RM	Camden 1 (Gasna 30P)	Camden 1 FIT (SB32)	2016	2	4.357	SB32/ReMAT	Solar Photovoltaic	Riverdale	CA
33R400	Exelon Generation Company	Multiple	2016	0	-60	RPS	Geothermal	Multiple	Multiple

*This Expiring Contract List does not include any projects that have re-contracted with PG&E or that are non-operational.

APPENDICES F.1 – F.5

Redacted in Entirety

August 8, 2016

APPENDIX G

Other Modeling Assumptions Informing Quantitative Calculation

August 8, 2016

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Other Modeling Assumptions Informing Quantitative Calculation[1]

Assumptions Related to Forecasted Generation	
Assumptions Related to Procurement Quantity Requirement	
Compliance Periods	• As implemented by Decision (“D.”) 11-12-020, SB 2 1X requires retail sellers of electricity to meet the following Renewables Portfolio Standard (“RPS”) procurement quantity requirements beginning on January 1, 2011: o An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013). o Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales). o Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales). o 33 percent of bundled retail sales in 2021 and all years thereafter. • Senate Bill (“SB”) 350 establishes the following new multi-year RPS compliance periods and interim compliance requirements: 40% by the end of 2021-2024; 45% by the end of 2025-2027; and 50% by the end of 2028-2030 and thereafter. o Implementation of SB 350 changes to RPS procurement requirements, including post-2020 compliance period procurement quantity requirements is ongoing in Rulemaking (“R.”) 15-02-020. For its 2016 RPS Plan, Pacific Gas and Electric Company (“PG&E”) assumes continuation of the Portfolio Quantity Requirements (“PQR”) methodology as implemented by D.11-12-020 for compliance periods 2 and 3 (i.e. a “straight-line” trajectory from the quantity for the prior compliance period to the concluding year of the current compliance period to yield the intervening year targets)

1 All assumptions in this table reflect an April, 2016 data vintage (with the exception of the internal sales forecast, which uses a July 2016 vintage) which is consistent with the data vintage of Appendices C1–C4.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Non-Qualifying Facility ("QF") Projects *Contracts Executed Post-2002*	• Except for the "OFF/Closely Watched" contract category (see Section 4), all non-QF signed contracts are assumed to deliver at 100% of contract volumes, and deliveries commence within the allowed delay provisions in the contract.
QF Non-Hydro Projects *Contracts Executed Pre-2002*	• Forecast is typically based on an average of the three most recent calendar year deliveries. • Year 2016 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
QF Hydro *Pre-2002 QF, Irrigation District, and Legacy Utility-Owned Assets*	• The forecast for hydro QFs is typically based on historical production, normalized for average year conditions, and then adjusted to reflect PG&E's latest internal hydro outlook. • Projects are forecasted at 84% of average water year generation for 2016 (based on PG&E's April 2016 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year 2016 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
Non-QF Hydro *Utility Owned Generation ("UOG") and Irrigation District Water Authority ("IDWA")*	• Forecasts reflect PG&E's best available projections for hydro conditions. • Projects are forecasted at 84% of average water year generation for 2016 (based on PG&E's April 2016 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year 2016 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
Future Volumes from Pre-Approved Programs	**E-SRG, E-PWF (Assembly Bill 1969 FIT)** • All deliveries from executed contracts are assumed at 100% of contract volumes. • Annual energy volumes (for non-operating projects) are modeled based on PG&E's best estimate for project start dates/initial energy delivery date. **Renewable Market Adjusting Tariff** • All deliveries from executed contracts are assumed at 100% of contract volumes. • Modeled start date for generic volumes assumed to begin 6/1/2017 and ramp up linearly until 1/1/2019, reaching a total of ~112 MW.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

	SB 1122 (Bioenergy Feed-in Tariff Program) • Modeled start date for generic volumes assumed to begin 1/1/2018 and ramp up linearly until 3/1/2019, reaching a total of ~112 MW. **PV Originally Authorized for PG&E Photovoltaic Program** • Consistent with PG&E's February 26, 2014 Petition for Modification ("PFM")[2] requesting to terminate the PV Program and modify the Renewable Auction Mechanism ("RAM") Decision process to procure the remaining PV Program volumes using RAM solicitation processes PG&E assumed that the RAM accommodates the remaining 137.5 megawatts ("MW") of PG&E's PV Program volumes. • For planning purposes, PG&E has assumed that a total of 137.5 MW will be coming online between 2019 and 2020.[3] • All deliveries from executed contracts are assumed at 100% of contract volumes. **BioRAM** • [redacted]
Re-contracting	• For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained: 1. PG&E does not yet have contractual commitments for these expiring volumes; 2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life; 3. Contract-renewal bids may not be competitive with offers for new projects received in future solicitations; and 4. Assuming re-contracted volumes obscures PG&E's current real need for additional energy in later years. • Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement of other new resources. • This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E's Annual RPS compliance filing that only shows PG&E's current contractual commitments.

2 Advice Letter 3809-E. http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RAM/ELEC_3809-E.pdf.
3 This assumption is based on a modeling vintage of April 2016.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Green Tariff Shared Renewables ("GTSR")	• PG&E allocates small amounts of generation from RPS-eligible resources to serve initial GTSR enrollees until new incremental resources procured for the GTSR program are sufficient to meet program needs. • When calculating PG&E's RPS position, GTSR volumes are removed from PG&E's RPS-eligible retail sales forecast. • PG&E incorporates any GTSR related impacts on its RPS compliance position into updates to its RNS.
Banking	• PG&E assumes that for the first two compliance periods (2011-2013 and 2014-2016) that (1) Category 3 products that do not exceed applicable portfolio content limits are not deducted from bankable volumes, (2) grandfathered (pre-June 1, 2010) short-term products are bankable, and (3) that banked volumes may be applied in any period onward. ○ PG&E's accounting is consistent with the direction set forth in D.12-06-038 for compliance periods one and two. • PG&E assumes that beginning in the 2017-2020 compliance period (1) Grandfathered (pre-June 1, 2010) and Category 1 products of any duration are bankable, (2) Category 2 and Category 3 products that fall within the portfolio balance requirements are not deducted from bankable volumes, and (3) that banked volumes may be applied in any period onward.
RPS Sales	• PG&E has developed a framework to assess whether to hold or sell excess RPS volumes, which will allow PG&E to rebalance its RPS portfolio to better align its RPS position with its RPS need. PG&E is requesting Commission review and approval of this framework as a part of the 2016 RPS Plan. If approved, the proposed framework will be used to determine future sales of bankable RPS volumes. The details of PG&E's sales framework are discussed in Appendix J.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Sales	
Bundled Retail Sales *RNS (App. C1)*	• Forecasts of retail sales for the first five years of the forecast were generated by PG&E's *Load Forecasting and Research* team in July 2016, and may be updated throughout the year as additional data becomes available. • Forecasts of retail sales beyond the first five years are sourced from the latest Long-Term Procurement Plan standardized planning assumptions, per the May 21, 2014 Administrative Law Judge Ruling in R.11-05-005 regarding the methodology for calculating the renewable net short. Sales forecast used is from the most recently approved bundled sales forecast filed in PG&E's 2014 Conformed Bundled Procurement Plan in Advice Letter 4750-E and approved June 15, 2016. • Monthly recorded sales replace forecasts as 2016 progresses.
Bundled Retail Sales *Alternate RNS* *(App. C2)*	• Forecasts of retail sales were generated by PG&E's *Load Forecasting and Research* team in July 2016, and may be updated throughout the year as additional data becomes available. • Monthly recorded sales replace forecasts as 2016 progresses.

APPENDIX H

Responses to Renewable Net Short Questions

August 8, 2016

Appendix H – Responses to Renewable Net Short Questions

The following presents PG&E's responses to questions set forth in the May 21, 2014 *Administrative Law Judge's Ruling on Renewable Net Short*.

RPS Compliance Risk

1. How do current and historical performance of online resources in your RPS portfolio impact future projections of RPS deliveries and your subsequent RNS?

PG&E considers historical performance of online resources in both of its models. First, it considers this performance in developing the generation forecast in its deterministic model. As discussed in Appendix G, future projections of RPS deliveries in the deterministic model are based on a blended three year average output for QF contracts.

In addition, within its stochastic model, PG&E considers RPS generation variability based on historical performance of each resource type. A probabilistic distribution is built for each resource based on its calculated coefficient of variation. This captures additional RPS generation variability above and beyond the variances that are captured in the deterministic model. Section 6.2.2 of the RPS Plan describes in more detail how historic generation variability from each resource is used as an input to the stochastic model.

2. Do you anticipate any future changes to the current bundled retail sales forecast? If so, describe how the anticipated changes impact the RNS.

PG&E's retail sales are impacted by many factors, including weather, economic growth or recession, technological change, energy efficiency, DA and CCA participation levels, and distributed generation. PG&E's most recent Sales Forecast used in the RPS Plan is an April 2016 updated internal sales forecast. It is important to emphasize that PG&E's Alternative Scenario is a forecast including a number of assumptions regarding events which may or may not occur. PG&E updates the bundled load forecasts annually to reflect any new events and capture actual load changes. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts. Changes in retail sales tend to be variable and persistent, making uncertainty around retail sales one of the largest drivers of RPS outcomes, particularly over time.

3. Do you expect curtailment of RPS projects to impact your projected RPS deliveries and subsequent RNS?

To the extent that RPS projects are economically bid and do not clear the market, or are curtailed for system reliability, PG&E expects that curtailment will impact its RNS. As described in Sections 6.2.3 and 11, the stochastic model evaluates uncertainty associated with RPS generation variability, including assumptions of future levels of RPS curtailment.

4. Are there any significant changes to the success rate of individual RPS projects that impact the RNS?

PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of 100% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, to 87% in PG&E's 2014 RPS Plan, and 99% in PG&E's 2015 RPS Plan.[1] This success rate is evolving and highly dependent on the nature of PG&E's portfolio and the general conditions in the renewable energy industry. While PG&E has continued to see a general trend towards higher project success rates, its revised success rate assumption reflects the recent removal of several projects from PG&E's portfolio due to contract termination and an update to the "Closely Watched" category described in Section 6.

In addition, to model the project failure variability inherent in project development, PG&E adds additional success rate assumptions to it stochastic model, which assume that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. These assumptions are used in order to calculate its stochastically-optimized net short (SONS). See the answer to question #5 below for details on these new assumptions.

5. As projects in development move towards their COD, are there any changes to the expected RPS deliveries? If so, how do these changes impact the RNS?

Yes. PG&E may adjust the expected delivery volumes in its deterministic model for RPS projects in development for various reasons. For example, counterparties may make adjustments to their project design, such as decreasing total project capacity, which may lead to changes in expected generation. Counterparties may also experience project delays which impact the delivery date for projects, shifting generation volumes further into the future. In extreme cases, as described in Section 6.1.2, PG&E may categorize projects experiencing considerable development challenges as "Closely

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1 PG&E's success rate discussed is more reflective of the success rate of its overall portfolio, and so this percentage does not convey that PG&E has no projects failing. Specifically, since almost all of PG&E's in-development projects are volumes procured through mandated programs with set targets, any projects that fail will be replaced through future solicitation rounds. Therefore the effect on PG&E's portfolio is that the amount of volumes projected has a very high project success rate, given that any failed project will be replaced with a new project, until the volumes come online.

Watched" and would in those cases reduce the expected delivery volumes from those projects to zero in its deterministic model. Moving a project to the "Closely Watched" category would therefore decrease future delivery volumes and increase the RNS. PG&E has an extensive program for monitoring the development status of RPS-eligible projects, and the deterministic model is updated regularly to reflect any relevant status changes.

In addition, PG&E further reduces its anticipated deliveries from future projects in its stochastic model, as described in more detail in Section 6.2.4. To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] or [redacted] chance of success. This success rate is based on experience, and although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Appendix F.2 show PG&E's simulated failure rate and for the period 2016-2030.

SUMMARY:
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Reference Above and Uncertainty it Represents	Deterministic Model	Stochastic Model
Question #2: Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years.	Distribution based on most recent (2016) PG&E bundled retail sales forecast.
Question #4 and #5: Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success.
Question #1: RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
Question #3: Curtailment[2]	None	Curtailment is modeled as increasing between the following data points: [redacted] in 2015 [redacted] in 2020 [redacted] in 2024 [redacted] in 2030

2 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information.

6. What is the appropriate amount of RECs above the PQR to maintain? Please provide a quantitative justification and elaborate on the need for maintaining banked RECs above the PQR.

As described in Sections 7 and 8, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]. However, because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a point forecast rather than a static target. Please see Section 7 for additional information.

7. What are your strategies for short-term management (10 years forward) and long-term management (10-20 years forward) of RECs above the PQR? Please discuss any plans to use RECs above the PQR for future RPS compliance and/or to sell RECs above the PQR.

As described in Sections 6 and 7, PG&E uses its stochastic model to optimize its procurement. This model currently forecasts Bank levels through [redacted] projecting that PG&E's forecasted Bank size [redacted] GWh by [redacted]. Under this projection, [redacted] Bank will be maintained as VMOP to manage additional risks and uncertainties associated with managing an RPS portfolio.

In the long-term, PG&E will use RECs above the PQR, as needed, to maintain an adequate Bank, as determined by the deterministic and stochastic model or similar means, in order to manage additional risks and uncertainties.

PG&E's optimization strategy includes consideration of sales of surplus procurement. Consistent with the Commission-approved RNS, PG&E's physical net short and cost projections do not include any future projected sales of bankable contracted deliveries. However, PG&E will consider selling surplus RPS volumes if it can still maintain adequate Bank and if market conditions are favorable. PG&E discusses a framework to assess whether to hold or to sell excess RPS volumes in Appendix J.

<u>**VMOP**</u>

8. Provide VMOP on both a short-term (10 years forward) and long-term (10-20 years forward) basis. This should include a discussion of all risk factors and a quantitative justification for the amount of VMOP.

As discussed in Sections 7 and 8, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. [redacted], PG&E believes it would be imprudent to use its entire projected Bank toward meeting the 50% RPS target, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, the Bank will help to avoid long-term over-procurement above the 50% target, and will thus reduce long-term costs of the RPS Program.

9. Please address the cost-effectiveness of different methods for meeting any projected VMOP procurement need, including application of forecast RECs above the PQR.

As discussed in Sections 6 and 7, PG&E's stochastic model optimizes its results to inform its RPS procurement strategy, which includes using a portion of the Bank as VMOP, to achieve the lowest cost possible given a specified risk of non-compliance. The model suggests a specific level of procurement and resulting Bank usage for each year. PG&E then uses these model results as a tool to guide its actual procurement strategy. While the model provides other possible VMOP usage given a specific level of non-compliance risk, these paths would not be minimum cost under the model's assumptions.

PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus RPS volumes if it can still maintain an adequate Bank and if market conditions are favorable. PG&E discusses a framework to assess whether to hold or to sell excess RPS volumes in Appendix J.

<u>Cost-Effectiveness</u>

10. Are there cost-effective opportunities to use banked RECs above the PQR for future RPS compliance in lieu of additional RPS procurement to meet the RNS?

As discussed in greater detail in Sections 6, 7, and 8 of this Plan, [redacted]. As long as PG&E can continue to maintain an adequate Bank that does not jeopardize PG&E's ability to manage its non-compliance risk and thus avoid being caught in a "seller's market," where PG&E would face potentially high market prices in order to meet near-term compliance deadlines.

Overall, PG&E can best meet the objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to purchase or sell RPS-eligible products consistent with its RPS Plan on a going-forward basis, continually adapting to these uncertain variables. PG&E will continue to use the stochastic model to help guide decisions around minimum Bank size needed to maintain PG&E's non-compliance risk of [redacted] for the period of [redacted]. PG&E will then procure any needed incremental volumes ratably over time.

11. How does your current RNS fit within the regulatory limitations for PCCs? Are there opportunities to optimize your portfolio by procuring RECs across different PCCs?

PG&E's current RPS portfolio consists of primarily Category 0 and 1 RECs. Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement.

While PG&E seeks opportunities across all product categories to procure the most cost-effective resources to achieve the RPS requirements, the pre-SB 350 restrictions on banking of excess procurement have limited PG&E's ability to fully optimize its portfolio. Under the current RPS rules, short-term contracts cannot count towards excess procurement eligible for banking toward a future RPS compliance period. The result is that any entity that has excess procurement during a particular compliance period is effectively restricted from procuring short-term contracts during that compliance period. Only when an entity does not exceed its compliance period target, is it able to count short-term procurement towards meeting its targets.

The changes to the RPS program under SB 350 enable banking of all category 0 and 1 RECs of any duration, beginning in the 2021-2024 compliance period for all entities, or as early as the 2017-2020 compliance period for any entities who elect to comply early with the new SB 350 minimum long-term requirements.[3] In addition, all retired Category 2 and Category 3 RECs that fall within the portfolio balance requirements are eligible to be counted towards PG&E's RPS procurement quantity requirement for the compliance period whether the RECs are associated with short-term or long-term contracts.

As PG&E currently maintains a bank in order to help mitigate procurement and load variability, the past inability for short-term contracts to contribute to the bank has restricted our mitigation strategy. The new banking provisions in SB 350 are intended to help address this issue, and should therefore be implemented in a way that provides adequate flexibility to retail sellers in meeting the RPS goals.

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3 Although the Commission has not yet implemented this new statutory language by specifying the manner or process by which a retail seller must notify the Commission of its intent to comply early with the minimum long-term requirements, PG&E intends this 2016 RPS Plan to provide such notice if the Commission ultimately determines that the notice should be provided as part of the annual RPS Plan submissions.

APPENDIX I

2016 Solicitation Protocol and Attachments

August 8, 2016

Pacific Gas and Electric Company®

Renewable Energy Sale - Request for Offers Solicitation Protocol

Issuance Date: _______________, 201_

Table of Contents

LIST OF ATTACHMENTS

I. Overview

A. Overview

Pacific Gas and Electric Company ("PG&E") is issuing this 2017 Renewable Energy Sale Request for Offers ("RFO" or "2017 Renewable Energy Sale RFO"). The 2017 Renewable Energy Sale RFO is intended to solicit offers ("Offers") from participants ("Participants" or "Bidders") to procure Portfolio Content Category 1 ("PCC 1") eligible renewable energy resource electricity product ("Product") from PG&E pursuant to a confirmation (the "Agreement"). This Solicitation Protocol describes the process by which PG&E seeks, evaluates, and accepts Offers in the RFO from winning Bidders ("Buyers").

The 2017 Renewable Energy Sale RFO complies with PG&E's 2016 RPS Plan, which was approved by the California Public Utilities Commission ("CPUC" or "Commission") in Decision xx-xx-xxx.

Subject to Bid pricing and other factors in this Solicitation Protocol, PG&E seeks to sell a volume of Product commensurate with Bid prices received. PG&E will utilize a proprietary price curve to determine the volume of Product available for sale at different price points.

PG&E will make all sales according to the terms and conditions set forth in the Agreement. This Solicitation Protocol sets forth the procedures a Bidder must follow in order to participate in the RFO. Capitalized terms used in this Solicitation Protocol, but not otherwise defined herein, have the meanings set forth in the Agreement.

B. Renewable Energy Sale RFO Communication

PG&E has established the 2017 Renewable Energy Sale RFO website at http://www.pge.com/rfo and click on "2017 Renewable Energy Sale RFO." This site will be where Bidders register and where all the RFO documents, information, announcements and questions and answers are posted and available to Bidders.

To promote accuracy and consistency of the information provided to all Bidders, PG&E encourages Bidders to submit any inquiries via e-mail to RenewableRFO@pge.com for matters related to the 2017 Renewable Energy Sale RFO. With respect to matters of general interest raised by any Bidder, PG&E may, without reference to the specific Bidder raising such matter or initiating the inquiry, post the questions and responses on its website. PG&E may, in its sole discretion, decline to respond to any email or other inquiry.

Any exchange of material information regarding this RFO between Bidder and PG&E must be submitted to both PG&E and the Independent Evaluator ("IE"). The IE is an independent, third party evaluator who is required by CPUC Decision 14-12-024 to ensure this RFO is conducted in a reasonable and neutral manner.

C. Schedule

The RFO schedule is subject to change to conform to any CPUC requirements but otherwise is at the discretion of PG&E. PG&E will post any schedule change on PG&E's 2017 Renewable Energy Sale RFO website. Also, as further described below, Bidders may register at PG&E's RFO website to receive notice of these and other RFO changes by electronic mail. PG&E will have no liability or responsibility to any Bidder for any change in the schedule or for failing to provide notice of any change.

The schedule for this RFO is (all times are in Pacific Prevailing Time ["PPT"]):

Table 1: 2017 Renewable Energy Sale RFO Schedule of Events (Tentative)

Date/Time	Event
Ongoing	Bidders may register online at PG&E's RFO website to receive notices regarding the RFO.
January 9, 2017	PG&E issues the RFO.
January 23, 2017 1:00 PM	Offers Due. Offer(s) must be submitted to the online platform at Power Advocate.
January 30, 2017	PG&E notifies shortlisted Participants.
March 6, 2017	PG&E and shortlisted Participants complete negotiation of an Agreement, which shall be subject to "CPUC Approval," as provided in the Agreement.
March 30, 2017	PG&E submits Agreements for CPUC Approval.

D. Events in the RFO Schedule

a. <u>Registration</u>. Bidders may register online to receive announcements and updates about this RFO at www.pge.com/rfo

b. <u>Issuance</u>. PG&E will issue the 2017 Renewable Energy Sale RFO and post the Solicitation Protocol, form of Agreement, and all other RFO materials on the 2017 Renewable Energy Sale RFO website.

c. <u>Offers Due</u>. Bids must be submitted via Power Advocate and must include all of the documents described in Section IV, Required Information. By submitting an Offer and responding to this RFO, the Bidder agrees to be bound by all of the terms, conditions and other provisions of this RFO and any changes or supplements to it that may be issued by PG&E.

d. <u>PG&E Selects Offers</u>. Selected Bids ("Selected Bids") will be notified via email. PG&E will select Bids according to the evaluation criteria described in Section III, Evaluation Criteria. Offers beyond the Selected Bids may be placed on a waitlist to be selected in order of evaluation results and selection constraints, should any Selected Bids fail to complete the RFO process.

e. Negotiation of Agreement. PG&E will engage in limited negotiations with Participants with Selected Bids.

f. Execution and Regulatory Approval. Once PG&E and the Participants with Selected Bids execute Agreements, if any, resulting from this RFO, PG&E will submit all such Agreements to the CPUC for approval via an advice letter filing. Additional regulatory approval information is provided in Section VII, Regulatory Approval.

E. Disclaimers for Rejecting Offers and/or Terminating this RFO

This RFO does not constitute an offer to sell and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the RFO. PG&E shall retain the right at any time, at its sole discretion, to reject any Offer on the grounds that it does not conform to the terms and conditions of this RFO and reserves the right to request information at any time during the solicitation process.

PG&E retains the discretion, subject to, if applicable, the approval of the CPUC, to: (a) reject any Offer for any reason, including but not limited to the basis that an Offer is the result of market manipulation or is not cost competitive or any other applicable reason; (b) modify this RFO and the form Agreement as it deems appropriate to implement the RFO and to comply with applicable law or other decisions or direction provided by the CPUC; and (c) terminate the RFO should the CPUC not authorize PG&E to sell the Product in the manner proposed in this RFO. In addition, PG&E reserves the right to either suspend or terminate this RFO at any time if such suspension is required by or with the approval of the CPUC. PG&E will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this Solicitation Protocol to any Bidder, whether submitting an Offer or not.

II. RFO Product and Goals

PG&E is seeking to sell Product with the exact volume to be determined based on the price of bids received.

A. Product Attributes

1. PCC 1 eligible renewable energy resource electricity product with the resources defined by PG&E.
2. Price: P15 or SP15 Day Ahead Index + REC Price to be specified by Buyer.
3. Location: Buyer to choose energy deliveries at NP15 DLAP or SP15 DLAP.
4. Scheduled Energy Deliveries: Buyer may propose energy delivery beginning April 2017 or later. Energy deliveries may be in any months or hours that are mutually agreeable.

5. Delivery Term: Shall begin on agreed upon date and end by December 31, 2017.

*If energy deliveries begin before CPUC Approval, PG&E will not transfer the corresponding RECs until CPUC Approval is obtained. Full contract price is expected to be paid regardless of CPUC approval. If CPUC approval is not obtained then Buyer will receive credit.

III. Evaluation Criteria

PG&E will evaluate Offers using the evaluation criteria outlined below.

A. Quantitative Evaluation

For Offers in the 2017 Renewable Energy Sale RFO, PG&E will consider Price offered as the sole quantitative value.

B. Qualitative Evaluation

For the 2017 Renewable Energy Sale RFO, PG&E will apply a qualitative adjustment factor for counterparties that have acceptable credit with PG&E and minimize proposed edits to the form of Agreement.

1. Credit

PG&E may consider the Participant's capability to perform all of its financial and financing obligations under the Agreement and PG&E's overall credit concentration with the Participant or its banks, including any of Participant's affiliates.

2. Agreement Modifications

PG&E may assess the materiality and cost impact of any of Participant's proposed modifications to the Agreement.

3. Other Qualitative Considerations

In addition to the criteria specifically listed above, PG&E may consider other qualitative factors that could impact the value of Offers, including, but not limited to: PG&E's past commercial experience with a Participant; Participant concentration; and existence of an acceptable EEI Master Agreement between PG&E and Participant.

IV. Required Information

A. Submission Overview

All Offer submittal information pertaining to this RFO will be hosted on the Power Advocate site. Telephonic, hardcopy or facsimile transmission of an Offer is not acceptable. In order to participate in this RFO, Bidders must register and be accepted through Power Advocate at the Public Registration Link:

TBA

PG&E strongly encourages Bidders to register with Power Advocate well before Offers are due. Detailed instructions for submitting Offer(s) and using Power Advocate are on PG&E's Renewable Energy Sale RFO website.

Electronic Documents: The electronic documents for the attachments must be in a Microsoft Word, Excel file or Adobe Acrobat PDF file as applicable. For each document, please include the Bidder's company name in each file name.

B. Required Forms

1. **Offer Package**

The following documents, which are on the 2017 Renewable Energy Sale RFO website, must be completed and included with each Offer:

a. Introductory Letter

b. Offer Form (Attachment A) - Bidder must provide all applicable information requested in the form and all inputs must match the respective information provided in other required documentation.

c. Redline of Agreement (Attachment B)

2. **Shortlist Documents (if applicable)**

If the Bidder is notified via an emailed letter that they are eligible for PG&E's Shortlist ("Shortlist Letter"), then they must complete the following documents:

a. Signed Shortlist Letter – Bidder must return a signed Shortlist Letter to PG&E, accepting the terms set forth in the Shortlist Letter and agreeing to continued participation of their Selected Offers in the 2017 Renewable Energy Sale RFO.

V. Confidentiality

No Bidder shall collaborate on or discuss with any other Bidder or potential Bidder Offer strategies, the substance of any Offer(s), including without limitation the price or any other terms or conditions of any Offer(s), or whether PG&E has Selected Offers or not.

All information and documents in Bidder's Offer that have been clearly identified and marked by Bidder as "Proprietary and Confidential" on each page on which confidential information appears shall be considered confidential information. PG&E shall not disclose such confidential information and documents to any third parties except for PG&E's employees, agents, counsel, accountants, advisors, or contractors who have a need to know such information and have agreed to keep such information confidential and except as provided otherwise in this section. In addition, Bidder's Offer will be disclosed to the IE.

Notwithstanding the foregoing, it is expressly contemplated that the information and documents submitted by Bidder in connection with this RFO, including Bidder's confidential information, may be provided to the CPUC, its staff, and the Procurement Review Group ("PRG"), and established pursuant to Decision 02-08-071. PG&E retains the right to disclose any information or documents provided by Bidder to the CPUC, the PRG, in the advice letter filing or in order to comply with any applicable law, regulation, or any exchange, control area or California Independent System Operator ("CAISO") rule, or order issued by a court or entity with competent jurisdiction over PG&E at any time even in the absence of a protective order, confidentiality agreement, or nondisclosure agreement, as the case may be, without notification to Bidder and without liability or any responsibility of PG&E to Bidder. PG&E cannot ensure that the CPUC will afford confidential treatment to Bidder's confidential information, or that confidentiality agreement or orders will be obtained from and/or honored by the PRG, the California Energy Commission ("CEC"), or the CPUC. By submitting an Offer, Bidder agrees to adhere and be bound by the confidentiality provisions described in this section.

The treatment of confidential information described above shall continue to apply to information related to Selected Offers.

VI. Procurement Review Group Review

Following completion of the evaluation and rankings of Offers, PG&E will submit the results of the evaluation and its recommendations to its PRG members. PG&E will consider any alternative recommendations proposed by the PRG. PG&E, in its sole discretion, shall determine whether any alternatives proposed by the PRG should be adopted. PG&E has no obligation to obtain the concurrence of the PRG with respect to any Offer.

PG&E assumes no responsibility for the actions of the PRG, including actions that may delay or otherwise affect the schedule for this Solicitation, including the timing of the selection of Offers and the obtaining of Regulatory Approval.

VII. Regulatory Approval

After Agreement execution, PG&E is required to submit executed Agreements to the CPUC for approval via an advice letter filing.

The effectiveness of any executed Agreement is expressly conditioned on CPUC approval of the Agreement ("Regulatory Approval").

VIII. Dispute Resolution

Except as expressly set forth in this Solicitation Protocol, by submitting an Offer, Bidder knowingly and voluntarily waives all remedies or damages at law or equity concerning or related in any way to the RFO, the Solicitation Protocol and/or any attachments to the Solicitation Protocol ("Waived Claims"). The assertion of any Waived Claims by Bidder may, to the extent that Bidder's Offer has not already been disqualified, automatically disqualify such Offer from further consideration in the RFO.

By submitting an Offer, Bidder agrees that the only forums in which Bidder may assert any challenge with respect to the conduct or results of the RFO is through the Alternative Dispute Resolution ("ADR") services provided by the CPUC pursuant to Resolution ALJ-185, August 25, 2005. The ADR process is voluntary in nature, and does not include processes, such as binding arbitration, that impose a solution on the disputing parties. PG&E will consider the use of ADR under the appropriate circumstances. Additional information about this program is available on the CPUC's website at the following link: www.cpuc.ca.gov/PUBLISHED/Agenda_resolution/47777.htm.

Participant further agrees that other than through the ADR process, the only means of challenging the conduct or results of the RFO is a protest to an Advice Letter Filing seeking approval of one or more Agreements entered into as a result of the RFO, that the sole basis for any such protest shall be that PG&E allegedly failed in a material respect to conduct the RFO in accordance with this Solicitation Protocol, and the exclusive remedy available to Bidder in the case of such a protest shall be an order of the CPUC that PG&E again conduct any portion of the RFO that the CPUC determines was not previously conducted in accordance with the Solicitation Protocol. Bidder expressly waives any and all other remedies, including, without limitation, compensatory and/or exemplary damages, restitution, injunctive relief, interest, costs, and/or attorney's fees. Unless PG&E elects to do otherwise in its sole discretion during the pendency of such a protest or ADR process, the RFO and any related regulatory proceedings related to the RFO, will continue as if the protest had not been filed, unless the CPUC has issued an order suspending the RFO or PG&E has elected to terminate the RFO.

Bidder agrees to indemnify and hold PG&E harmless from any and all claims by any other Bidder asserted in response to the assertion of a Waived Claim by Bidder or as a result of a Bidder's protest to an advice letter filing with the CPUC resulting from the RFO.

Except as expressly provided in this Solicitation Protocol, nothing herein including Bidder's waiver of the Waived Claims as set forth above, shall in any way limit or otherwise affect the rights and remedies of PG&E. Nothing in this Solicitation Protocol is intended to prevent any Bidder from informally communicating with the CPUC or its staff regarding this RFO.

IX. Termination of the RFO-Related Matters

PG&E reserves the right at any time, in its sole discretion, to terminate the RFO for any reason without prior notification to Bidders and without liability to, or responsibility of, PG&E or anyone acting on PG&E's behalf. Without limitation, grounds for termination of the RFO may include the assertion of any Waived Claims by a Bidder or a determination by PG&E that, following evaluation of the Offers, there are no Offers that meet the requirements of this RFO.

PG&E reserves the right to terminate further participation in this process by any Bidder, to accept any Offer or to enter into any Agreement, and to reject any or all Offers, all without notice and without assigning any reasons and without liability to PG&E or anyone acting on PG&E's behalf. PG&E shall have no obligation to consider any Offer.

In the event of termination of the RFO for any reason, PG&E will not reimburse Bidder for any expenses incurred in connection with the RFO. PG&E shall have no obligation to reimburse any Bidder's expenses regardless of whether such Bidder's Offer is selected, not selected, rejected or disqualified. Unless earlier terminated, the RFO will terminate automatically upon the execution of one or more Agreements by Participants with Selected Bids. In the event that no Agreements are executed, then the RFO will terminate automatically on July 31, 2017.

X. Bidder's Representations and Warranties

1. By submitting an Offer and clicking "Yes" to the "Acknowledgment of Protocol" section of the Offer Form, Bidder agrees to be bound by the conditions of the RFO, and makes the following representations, warranties, and covenants to PG&E, which representations, warranties, and covenants shall be deemed to be incorporated in their entireties into each of Bidder's Offers. Bidder agrees that an electronic signature of a duly authorized representative of Bidder shall be the same as delivery of an executed original document for purposes of the Offer Form.

    - Bidder has read, understands and agrees to be bound by all terms, conditions and other provisions of this Solicitation Protocol;

    - Bidder has had the opportunity to seek independent legal and financial advice of its own choosing with respect to the RFO and this Solicitation Protocol, including the submittal forms and documents listed in this Solicitation Protocol which are posted on the RFO website;

- Bidder has obtained all necessary authorizations, approvals and waivers, if any, required by Bidder to submit its Offer pursuant to the terms of this Solicitation Protocol and to enter into an Agreement with PG&E;

- Bidder's Offer complies with all applicable laws;

- Bidder has not engaged, and covenants that it will not engage, in any communications with any other actual or potential Bidder in the RFO concerning this solicitation, price terms in Bidder's Offer, or related matters and has not engaged in collusion or other unlawful or unfair business practices in connection with the RFO;

- Any Offer submitted by Bidder is subject only to PG&E's acceptance, in PG&E's sole discretion; and

- The information submitted by Bidder to PG&E in connection with the RFO and all information submitted as part of any Offer is true and accurate as of the date of Bidder's submission. Bidder also covenants that it will promptly update such information with PG&E upon any material change thereto.

2. By submitting an Offer, Bidder acknowledges and agrees:

    - That PG&E may rely on any or all of Bidder's representations, warranties, and covenants in the RFO (including any Offer submitted by Bidder); and

    - That in PG&E's evaluation of Offers pursuant to the RFO, PG&E has the right to disqualify a Bidder that is unwilling or unable to meet any other requirement of the RFO, as determined by PG&E in its sole discretion.

3. BY SUBMITTING AN OFFER, BIDDER HEREBY ACKNOWLEDGES AND AGREES THAT ANY BREACH BY BIDDER OF ANY OF THE REPRESENTATIONS, WARRANTIES AND COVENANTS IN THESE RFO INSTRUCTIONS SHALL CONSTITUTE GROUNDS FOR IMMEDIATE DISQUALIFICATION OF SUCH BIDDER, IN ADDITION TO ANY OTHER REMEDIES THAT MAY BE AVAILABLE TO PG&E UNDER APPLICABLE LAW, AND DEPENDING ON THE NATURE OF THE BREACH, MAY ALSO BE GROUNDS FOR TERMINATING THE RFO IN ITS ENTIRETY.

APPENDIX I

2016 Solicitation Protocol
Attachment A: Renewable Energy Sale Offer Form

August 8, 2016

Pacific Gas and Electric Company

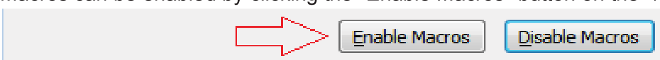
Instructions for Attachment: Bundled Energy Plus REC

Version 2016.1

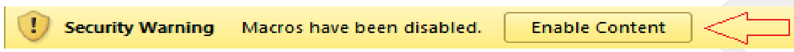
Unless otherwise provided herein, all capitalized terms shall have the meaning ascribed to them in PG&E's Renewables Portfolio Standard Solicitation Protocol dated December 18, 2014, or the applicable Agreement.

PLEASE BE SURE TO ENABLE MACROS. OTHERWISE THIS WOOKBOOK WILL NOT FUNCTION PROPERLY.

Macros can be enabled by clicking the "Enable Macros" button on the "Microsoft Excel Security Notice" that is displayed before the form opens…



…or by clicking the "Enable Content" button that is sometimes displayed at the top of the screen when the form first opens.



Important Notes

1. Please ensure to submit this file in **Microsoft Excel**. **Other versions will not be accepted**.
2. The workbook is set to recalculate automatically; however, if for some reason it is not refreshed automatically, please press **F9** to refresh.
3. The workbook functions best using **Microsoft Excel 2010** on a **Windows XP Operating System.**

Every cell with a yellow background **MUST** be filled out. As you fill these fields out, the yellow background will disappear.   If all fields have been filled out, you should see the word "Complete" appear at the top of the page. If this tab does not have this validation done and the word "Complete" does not appear, the form will be deemed invalid and returned to you.

Pacific Gas and Electric Company

Participant Proposal and Contact Information

There are 19 missing inputs. Please fill in all yellow highlighted cells.

Contact Information				
Counterparty/Legal Entity Name				
Street Address				
City		State		Zip Code
Country				
Company Website				

Acknowledgement of Protocol

By selecting "Yes" participant hereby agrees to the terms of the Solicitation Protocol and TERMS OF THE PROTOCOL AGREEMENT, as provided in Attachment A. Participant acknowledges that any costs incurred to become eligible or remain eligible for the solicitation, and any costs incurred to prepare an offer for this RFO are solely the responsibility of Participant.

Electronic Signature		Select 'Yes' to certify that the typed name acts as your electronic signature.	
Title			

Participant Authorization

By selecting 'Yes", participant hereby confirms that they are "a duly authorized representative of Participant."

Electronic Signature		Select 'Yes' to certify that the typed name acts as your electronic signature.	
Title			

Attestation

By providing the electronic signature, below, Participant hereby attests that all information provided in this Offer Package and in response to this RPS RFO is true and correct to the best of Participant's knowledge as of the date such information is provide.

Electronic Signature		Select 'Yes' to certify that the typed name acts as your electronic signature.	
Title			

Pacific Gas and Electric Company

REC Quantity

There are 26 missing inputs. Please fill in all yellow highlighted cells.

Please provide a forecast of REC quantity by on-peak and off-peak, by month for 2017

Month	On-Peak	Off-Peak
Jan		
Feb		
Mar		
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		

Delivery Point <Choose>

Price (Rec Premium)

APPENDIX I

2016 Solicitation Protocol
Attachment B: Renewable Energy Sale Confirmation

August 8, 2016

EEI MASTER POWER PURCHASE AND SALE AGREEMENT
SHORT TERM SALES CONFIRMATION
BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY
AND
[COUNTERPARTY]

This confirmation ("Confirmation") confirms the transaction ("Transaction") between Pacific Gas and Electric Company ("Seller", "PG&E" or "Party B") and ***[Counterparty]*** ("Buyer" or "Party A"), each individually a "Party" and together the "Parties", effective as of __________, 201_ (the "Confirmation Effective Date") regarding the sale and purchase of the Product, as such term is defined below in Article 1, in accordance with and subject to the terms and provisions of the EEI Master Power Purchase and Sale Agreement, together with the Cover Sheet, any amendments and annexes thereto between Seller and Buyer dated as of __________, 201_ (collectively, the "Master Agreement"), and Paragraph 10 of the EEI Collateral Annex to the Master Agreement (Paragraph 10 and the Collateral Annex are both referred to herein as the "Collateral Annex")(the Master Agreement and the Collateral Annex shall be collectively referred to as the "EEI Agreement"). The EEI Agreement and this Confirmation shall be collectively referred to herein as the "Agreement." Capitalized terms used but not defined in this Confirmation shall have the meanings ascribed to them in the EEI Agreement or the Tariff. If any term in this Confirmation conflicts with the EEI Agreement or Tariff, the definitions set forth in the Confirmation shall supersede.

[Standard contract terms and conditions shown in shaded text are those that "may not be modified" per CPUC Decisions ("D.") 07-11-025; D.10-03-021, as modified by D.11-01-025; and D.13-11-024.]

ARTICLE 1
COMMERCIAL TERMS

Seller: PACIFIC GAS AND ELECTRIC COMPANY		**Buyer: _*[Counterparty]*_______**
Scheduling:	Seller: _________________ Day Ahead: (415) 973-6222 Alternative: (415) 973-4500	Buyer: ___________________ Day Ahead: _______________ Alternative: _______________
Product:	Electric Energy and the associated Green Attributes from the Project.	
Project:	All Product sold hereunder shall be generated by the facility or facilities listed in Appendix A to this Confirmation (individually and collectively, the "Project"). The Parties acknowledge and agree that Seller shall have sole discretion throughout the Term to select the specific facility or facilities from Appendix A for designation as the Project that will generate some or all of the Product. The Parties further acknowledge and agree that Buyer is not entitled to any additional Green Attributes produced by the Project above and beyond the Total Quantity, and Buyer is not entitled to any additional Electric Energy produced by the Project beyond the amount of Energy Quantity.	
Quantity:	Green Attributes: "Total Quantity" shall be equal to _____ MWhs of Green Attributes during the Delivery Term, represented by an equal number of WREGIS Certificates.	

	Electric Energy: an equivalent of ___ MWh for each of the following hours ____ (e.g. On Peak, Off Peak, other) for the months of ________, or up to a total of _____ MWhs for the Delivery Term (the "Energy Quantity"). Seller will notify the Buyer each day according to the WECC Preschedule Calendar as to the amounts Seller will deliver in each hour of the following day(s) per the timing dictated by the WECC Preschedule Calendar ("Hourly Amount"). This notification process for the Hourly Amounts will occur until the Energy Quantity has been delivered. In no event shall Seller deliver to Buyer more than the Energy Quantity during the Delivery Term. In the event Seller does not deliver any of the above specified or agreed to quantities for any reason, except as excused by Force Majeure, the Parties shall agree upon the make-up Schedules for any undelivered quantities. Parties shall make best efforts to determine make-up Schedules before the next approved Scheduling day as identified by the WECC Preschedule Calendar. If the Parties are unable to mutually agree to a make-up Schedule, the Total Quantity will be reduced by the Energy Quantity undelivered by Seller to Buyer.
Energy Price:	Means the Index Price for each MWh of Delivered Energy.
Green Attribute Price:	Means $_____ per MWh for Green Attributes conveyed to Buyer in accordance with the terms of this Agreement.
Contract Price:	Energy Price plus Green Attribute Price.
Term:	The Term of this Transaction shall commence upon the Confirmation Effective Date and shall continue until the end of the Delivery Term and all other obligations of the Parties under this Agreement have been satisfied, unless terminated earlier due to failure to satisfy the Green Attributes Conditions Precedent, or as otherwise provided in the Agreement; provided, however, any termination arising due to failure to meet the Green Attributes Conditions Precedent shall only cause termination of the obligations with respect to the Green Attributes under this Confirmation, and shall not affect the Parties' obligations with respect to the Energy Quantity.
Credit Provisions:	Credit requirements pertaining to the Electric Energy portion of this Transaction shall be governed by the EEI Agreement and, if applicable, the Collateral Annex. In addition, Buyer shall, within five (5) Business Days following the Confirmation Effective Date, provide to and maintain with Seller, a Letter of Credit or cash in the amount of fifteen percent (15%) of the total notional value of the Green Attributes to satisfy the credit requirements for the Green Attributes portion of this Transaction, as long as Buyer or its Guarantor, if any, does not maintain a Credit Rating of at least BBB- by S&P or Baa3 by Moody's.
Delivery Term:	The "Delivery Term" shall include the Energy Delivery Period and the Green Attribute Delivery Period; provided that, for purposes of Sections 6.1(a) and (b) of this Confirmation only, "Delivery Term" shall mean the Green Attribute Delivery Period.
Energy Delivery Period:	The "Energy Delivery Period" shall commence on __________, 201_, and shall end on the earlier of (a) the conclusion of hour ending 2400 (PPT) on _________, 201_ and (b) the last day Seller delivers Electric Energy to Buyer in satisfaction of the Energy Quantity pursuant to the terms of this Confirmation.

Green Attribute Delivery Period:	Subject to satisfaction or waiver in writing by both Parties of the Green Attributes Conditions Precedent in the section entitled "Conditions Precedent to the Green Attribute Obligations" below, the "Green Attribute Delivery Period" shall commence on the date Seller first conveys Green Attributes associated with the Delivered Energy from the Project to Buyer and will end on the date Seller has delivered the Total Quantity to Buyer. During the Green Attribute Delivery Period, Seller shall cause the Green Attributes associated with the Delivered Energy from the Project to meet the Total Quantity.
Delivery Point:	The "Delivery Point" shall be ______ ***[Seller to insert Existing Zone Generation Trading Hub: NP15, SP15, ZP26]***
Scheduling Obligations:	For each hour of each day in the Energy Delivery Period, Seller and Buyer or Buyer's designee shall Schedule the Hourly Amount of Electric Energy as an IST in the Integrated Forward Market ("IFM") at the Delivery Point on a day-ahead basis in accordance with the Tariff. By 1600 (PPT) on each day prior to the Scheduling day, consistent with the WECC Preschedule Calendar, Seller shall notify Buyer of the Hourly Amounts by email. In the event that the IST fails in any hour of the IFM, the Parties agree that a subsequent IST at the Delivery Point for the Hourly Amount shall be rescheduled for that failed hour in the Real-Time Market pursuant to the Tariff. Seller shall Schedule and deliver to Buyer the Hourly Amount of Electric Energy over all hours in all days during the Energy Delivery Period
Conditions Precedent to the Green Attribute Obligations:	Notwithstanding any other provision of this Confirmation to the contrary, all of the obligations with respect to the Green Attributes and the Green Attribute Delivery Period are conditioned upon obtaining or waiving CPUC Approval of this Transaction ("Green Attributes Conditions Precedent").

ARTICLE 2
DEFINITIONS

2.1 "Balancing Authority" has the meaning set forth in the CAISO Tariff.

2.2 "Balancing Authority Area" has the meaning set forth in the CAISO Tariff.

2.3 "Business Day" means any day except a Saturday, Sunday, a Federal Reserve Bank holiday, or a calendar holiday, and shall be between the hours of 8:00 a.m. and 5:00 p.m. local time for the relevant Party's principal place of business where the relevant Party, in each instance unless otherwise specified, shall be the Party from whom the Notice, payment or delivery is being sent and by whom the Notice or payment or delivery is to be received.

2.4 "California Renewables Portfolio Standard" or "RPS" means the renewable energy program and policies established by California State Senate Bills 1038 and 1078 as amended by Senate Bill SB1X, codified in California Public Utilities Code Sections 399.11 through 399.32 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

2.5 "CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

2.6 "CAISO Grid" has the same meaning as "CAISO Controlled Grid" as defined in the CAISO Tariff.

2.7 "CEC" means the California Energy Commission or its successor agency.

2.8 "Confirmation Effective Date" has the meaning set forth in the preamble.

2.9 "CPUC" means the California Public Utilities Commission, or successor entity.

2.10 "CPUC Approval" means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer's administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement from an eligible renewable energy resource for purposes of determining Buyer's compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 *et seq.*), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

For purposes of this section, a CPUC Energy Division disposition which contains such findings or deems approved an advice letter requesting such findings shall be deemed to satisfy the CPUC decision requirement.

For the purpose of this Section 2.10 only, the reference to "Buyer" shall mean "Seller".

2.11 "Credit Rating" means, with respect to any entity, (a) the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements), or (b) if such entity does not have a rating for its unsecured, senior long-term debt obligations, then the rating assigned to such entity as an issuer rating by S&P and/or Moody's. If the entity is rated by both S&P and Moody's and such ratings are not equivalent, the lower of the two ratings shall determine the Credit Rating. If the entity is rated by either S&P or Moody's, but not both, then the available rating shall determine the Credit Rating.

2.12 "Delivered Energy" means the Electric Energy from the Project that is delivered by Seller to Buyer at the Delivery Point.

2.13 "Electric Energy" means three-phase, 60-cycle alternating current electric energy measured in MWh and net of auxiliary loads and station electrical uses (unless otherwise specified).

2.14 "Eligible Renewable Energy Resource" or "ERR" has the meaning set forth in California Public Utilities Code Section 399.12 and California Public Resources Code Section 25741, as either code provision is amended or supplemented from time to time.

2.15 "Governmental Authority" means any federal, state, local or municipal government, governmental department, commission, board, bureau, agency, or instrumentality, or any judicial, regulatory or administrative body, having jurisdiction as to the matter in question.

2.16 "Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (a) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (b) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by Law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere[1]; (c) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state Law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local Law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Electric Energy. Green Attributes do not include (i) any Electric Energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project. ***[To the extent the Project is a biomethane facility, the Parties shall modify this definition as necessary to ensure that it, and Section 3.2(a), will not conflict with language that will need be added to address biomethane transactions, pursuant to CPUC D.13-11-024, pgs 21-24.]***

2.17 "Index Price" means the CAISO Integrated Forward Market Day-Ahead or Real-Time price (as such term is defined in the Tariff) associated with the validated IST for the Delivery Point for each applicable hour as published by the CAISO on the CAISO website; or any successor thereto, unless a substitute publication and/or index is mutually agreed to by the Parties, weighted for the quantity of Electric Energy that is delivered under this Agreement for each settlement interval associated with the validated IST.

2.18 "Integrated Forward Market" or "IFM" has the meaning set forth in the Tariff.

2.19 "IST" means the Inter-SC Trade, as that term is defined in the Tariff.

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

2.20 "Law" means any statute, law, treaty, rule, regulation, CEC guidance document, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Confirmation Effective Date, and which becomes effective after the Confirmation Effective Date; or any binding interpretation of the foregoing. For purposes of the definition of "CPUC Approval" and Sections 6.1(a), 6.1(b) and 8.3(b) in this Confirmation, the term "law" shall have the meaning set forth in this definition.

2.21 "Letter of Credit" means an irrevocable, non-transferable, standby letter of credit the form of which must be substantially as contained in Appendix B to this Confirmation; provided, that, if the issuer is a U.S. branch of a foreign commercial bank, the intended beneficiary may require changes to such form; and the issuer must be a Qualified Institution on the date of delivery of the Letter of Credit to the Secured Party. In case of a conflict of this definition with any other definition of "Letter of Credit" contained in the EEI Agreement or any exhibit or annex thereto, this definition shall supersede any such other definition for purposes of the Transaction to which this Confirmation applies.

2.22 "Letter of Credit Default" means with respect to a Letter of Credit, the occurrence of any of the following events: (a) the issuer of such Letter of Credit shall cease to be a Qualified Institution; (b) the issuer of the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit; (c) the issuer of such Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; (d) such Letter of Credit shall expire or terminate, or shall fail or cease to be in full force and effect at any time during the term of the Agreement, in any case without replacement; or (e) the issuer of such Letter of Credit shall become Bankrupt; provided however, that no Letter of Credit Default shall occur or be continuing in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be canceled or returned to a Party in accordance with the terms of this Agreement.

2.23 "Notice" means written communications by a Party to be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail). The Master Agreement contains the names and addresses to be used for Notices.

2.24 "PPT" means Pacific Prevailing Time

2.25 "Qualified Institution" means either a U.S. commercial bank or a foreign bank issuing a Letter of Credit through its U.S. branch; and in each case the issuing U.S. commercial bank or foreign bank must be acceptable to intended beneficiary in its sole discretion and such bank must have a Credit Rating of at least (a) "A-, with a stable designation" from S&P and "A3, with a stable designation" from Moody's, if such bank is rated by both S&P and Moody's; or (b) "A-, with a stable designation" from S&P or "A3, with a stable designation" from Moody's, if such bank is rated by either S&P or Moody's, but not both, even if such bank was rated by both S&P and Moody's as of the date of issuance of the Letter of Credit but ceases to be rated by either, but not both of those rating agencies.

2.26 "Real-Time Market" has the meaning set forth in the Tariff and shall include any market that the CAISO may establish prior to or during the Term that clears at an interval between the Day-Ahead Market and the Real-Time Market.

2.27 "Renewable Energy Credit" or "REC" has the meaning set forth in California Public Utilities Code Section 399.12(h) and CPUC Decision 08-08-028, as may be amended from time to time or as further defined or supplemented by Law.

2.28 "Tariff" means the CAISO Fifth Replacement FERC Electric Tariff and protocol provisions, including any CAISO-published procedures or business practice manuals, as they may be amended, supplemented or replaced (in whole or in part) from time to time.

2.29 "WECC Preschedule Calendar" means the annual preschedule calendar set by the WECC that defines the timing for scheduling of energy transmission.

2.30 "WREGIS" means the Western Renewable Energy Generation Information System or any successor renewable energy tracking program.

2.31 "WREGIS Certificate" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

2.32 "WREGIS Operating Rules" means the operating rules and requirements adopted by WREGIS.

ARTICLE 3
CONVEYANCE OF ENERGY AND GREEN ATTRIBUTES

3.1 Seller's Conveyance of Energy

Beginning on the first day of the Energy Delivery Period and throughout the Energy Delivery Period, Seller shall deliver and sell, and Buyer shall purchase and receive, the Electric Energy subject to the terms and conditions of, and in accordance with the Schedules established pursuant to, this Agreement.

3.2 Seller's Conveyance of Green Attributes

(a) Green Attributes. Seller hereby provides and conveys all Green Attributes associated with all electricity generation from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Project. ***[To the extent the Project is a biomethane facility, the Parties shall modify this section as necessary to ensure that it, and the definition of "Green Attributes", will not conflict with language that will need be added to address biomethane transactions, pursuant to CPUC D.13-11-024, pgs 21-24.]***

Notwithstanding the foregoing, Seller shall only convey Green Attributes to meet the Total Quantity from the Project and only during the Green Attribute Delivery Period.

(b) The Green Attributes in the amount of the Total Quantity are delivered and conveyed upon completion of the following actions:

(i) During the Term, Seller, at its own cost and expense, shall maintain its registration with WREGIS. Seller shall, at its sole expense, use WREGIS as required pursuant to the WREGIS Operating Rules to effectuate the transfer of Green Attributes to Buyer in accordance with WREGIS reporting protocols and WREGIS Operating Rules.

(ii) During the Green Attribute Delivery Period, Seller shall deliver and convey the Green Attributes associated with the Delivered Energy from the Project, to meet the Total Quantity, within the later of (A) twenty-five (25) Business Days following the day the WREGIS Certificates for the Green Attributes were deposited into Seller's WREGIS account; and (B) twenty-five (25) Business Days following the satisfaction or waiver by both Parties of the Green Attributes Conditions Precedent, by transferring such WREGIS Certificates, in accordance with the rules and regulations of WREGIS, equivalent to the quantity of Green Attributes, to Buyer into Buyer's WREGIS account such that all right, title and interest in and to the WREGIS Certificates shall transfer from Seller to Buyer.

ARTICLE 4
CPUC FILING AND APPROVAL

4.1 **Filing for CPUC Approval.**

Within [____] days after the Confirmation Effective Date, Seller shall file with the CPUC a request for CPUC Approval. Buyer shall use commercially reasonable efforts to support Seller in obtaining CPUC Approval. Seller has no obligation to seek rehearing or to appeal a CPUC decision which fails to approve this Confirmation or which contains findings required for CPUC Approval with conditions or modifications unacceptable to either Party. Notwithstanding anything to the contrary in the Confirmation, Seller shall not have any obligation or liability to Buyer or any third party for any action or inaction of the CPUC or other Governmental Authority affecting the status of this Confirmation as a Category 1 Transaction.

4.2 **Green Attributes Termination Right.**

Either Party, in its sole discretion, has the right to terminate the rights and obligations with respect to the Green Attributes under this Confirmation at any time, upon Notice to the other Party in accordance with Article 10.7 of the EEI Agreement, which such Notice will be effective [____] Business Day(s) after such Notice is given, if: (a) the CPUC issues a final and non-appealable order not approving this Confirmation in its entirety, (b) the CPUC issues a final and non-appealable order which contains conditions or modifications unacceptable to either Party, (c) approval by the CPUC has not been obtained by Seller on or before [____] days from the date on which Seller files this Confirmation for CPUC Approval.

4.3 **Effect of Termination.**

Any termination made by a Party under Section 4.2 shall be without liability or obligation relating to delivery of Green Attributes, other than those obligations or liabilities that occurred prior to the termination date and shall have no effect on the status of the EEI Agreement. For the avoidance of doubt, if the obligations with respect to the Green Attributes are terminated pursuant to this Article 4, the Green Attributes Conditions Precedent shall be deemed to have not been satisfied. In the event that a condition or event specified in Sections 4.2(a) through (d) occurs following the conclusion of the Energy Delivery Period, and the obligations with respect to the delivery of Green Attributes are terminated pursuant to Section 4.2, such termination shall not affect any obligations or liabilities with respect to delivery of the Energy Quantities arising prior to such termination, all of which shall be performed in accordance with the terms of the Transaction, the Confirmation, and the EEI Agreement, as applicable.

ARTICLE 5
COMPENSATION

5.1 Calculation Period.

The "Calculation Period" shall be each calendar month or portion thereof during the Term that a Product, which may include Electric Energy and/or Green Attributes in any given calendar month or portion thereof, is transferred pursuant to Article 3 of this Confirmation.

5.2 Monthly Cash Settlement Amount.

Buyer shall pay Seller the Monthly Cash Settlement Amount, in arrears, for each Calculation Period. The "Monthly Cash Settlement Amount" for a particular Calculation Period shall be equal to the sum of (a) plus (b), where:

(a) equals the sum, over all hours of the Calculation Period, of the applicable Energy Price for each hour when Delivered Energy is scheduled by Seller, multiplied by the quantity of Delivered Energy during that hour; and

(b) equals the Green Attribute Price multiplied by the quantity of Green Attributes (in MWhs) that were delivered to Buyer (credited to Buyer's WREGIS account) during the Calculation Period.

5.3 Payment Date.

Notwithstanding anything to the contrary in Article Six of the EEI Agreement, payment of each Monthly Cash Settlement Amount by Buyer to Seller under this Confirmation shall be due and payable on or before the later of (a) the twentieth (20th) day of the month in which the Buyer receives from Seller an invoice for the Calculation Period to which the Monthly Cash Settlement Amount pertains, or (b) within ten (10) Business Days following receipt of an invoice issued by Seller for the applicable Calculation Period. Payment to Seller shall be made by electronic funds transfer pursuant to the following:

[***To be provided***.]

With a copy to:

[***To be provided.***]

5.4 Invoices.

The invoice shall include a statement detailing the portion of Product transferred to Buyer during the applicable Calculation Period. For purposes of this Confirmation, Buyer shall be deemed to have received an invoice upon the receipt of a PDF format of the invoice. Invoices to Buyer will be sent by facsimile or email to:

____
Attn:
Phone:
Facsimile:
Email:

With a copy to:

[***To be provided.***]

ARTICLE 6
REPRESENTATIONS, WARRANTIES AND COVENANTS

6.1 Seller's Representation, Warranties, and Covenants

(a) Seller Representations and Warranties. Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(b) Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(c) Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

(i) For the avoidance of doubt, the term "contract" as used in the immediately preceding paragraph means this Confirmation. For further clarity, the phrase "first delivery" as used in the immediately preceding paragraph means the first delivery of Green Attributes in the Green Attribute Delivery Period.

(d) In addition to the foregoing, Seller warrants, represents and covenants, as of the Confirmation Effective Date and throughout the Delivery Term, that:

(i) Seller has the contractual rights to sell all right, title, and interest in the Product agreed to be delivered hereunder;

(ii) Seller has not sold the Product to be delivered under this Confirmation to any other person or entity;

(iii) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code (as in effect as of the Execution Date of this Confirmation);

(iv) at the time of delivery, all rights, title, and interest in the Product to be delivered under this Confirmation are free and clear of all liens, taxes, claims, security interests, or other encumbrances of any kind whatsoever;

(v) Seller shall not substitute or purchase any Product from any other generating resource other than the Project or the market for delivery hereunder; and

(vi) the facility(s) designated as the Project and all electrical output from the facility(s) designated as the Project are, or will be by the date any Green Attributes are delivered to Buyer from such facility, registered with WREGIS as RPS-eligible.

(e) Seller makes no representation about the eligibility of the Product to qualify as excess procurement pursuant to California Public Utilities Code Section 399.13(a)(4)(B).

6.2 <u>Seller's Representation, Warranties, and Covenants Related to the Project</u>

Seller warrants, represents and covenants that at the time of the Confirmation Effective Date the Project is connected to the CAISO Grid, is within the CAISO Balancing Authority Area, and is under the control of CAISO.

6.3 To the extent a change in Law occurs after the Confirmation Effective Date that causes the representations, warranties, and/or covenants in Section 6.1or 6.2 to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in Law.

6.4 "Commercially reasonable efforts" as set forth in this Article 6 of this Confirmation and as applicable to Seller only shall not require Seller to incur out-of-pocket expenses in excess of twenty-five thousand dollars ($25,000.00) in the aggregate during the Term.

ARTICLE 7
TERMINATION AND CALCULATION OF TERMINATION PAYMENT

7.1 In the event this Transaction becomes a Terminated Transaction pursuant to Section 5.2 of the EEI Agreement, then the Settlement Amount with respect to this Transaction shall not be calculated in accordance with the EEI Agreement, but instead shall be calculated as follows:

The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for the Terminated Transaction for this Confirmation. Third parties supplying information for purposes of the calculation of Gains or Losses may include, without limitation, dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information. If the Non-Defaulting Party uses the market price for a comparable transaction to determine the Gains or Losses, such price should be determined by using the average of market quotations provided by three (3) or more bona fide unaffiliated market participants. If the number of available quotes is three, then the average of the three quotes shall be deemed to be the market price. Where a quote is in the form of bid and ask prices, the price that is to be used in the averaging is the midpoint between the bid and ask price. The quotes obtained shall be: (a) for a like amount, (b) of the same Product, (c) at the same Delivery Point, (d) for the remaining Delivery Term, and (e) any other commercially reasonable manner.

7.2 For the purposes of this Confirmation only, if the Non-Defaulting Party's aggregate Gains exceed its aggregate Losses and Costs, if any, resulting from the termination of the Terminated Transaction, the Settlement Amount for the purposes of this Confirmation only shall be zero.

ARTICLE 8
GENERAL PROVISIONS

8.1 Buyer Audit Rights

In addition to any audit rights provided under the EEI Agreement, Seller shall, during the Term as may be requested by Buyer, provide documentation, which may include, for example, meter data as recorded by a meter approved by the Project's governing Balancing Authority, sufficient to demonstrate that the Product has been conveyed and delivered, subject to the terms of this Confirmation, to Buyer.

8.2 Facility Identification

Although Seller has sole discretion throughout the Term to select the Project, Seller anticipates that it will designate the facilities as set forth on Appendix A as the Project from which the Product will be delivered (collectively the "Primary Facilities").

If Seller determines that the Product delivered in a calendar month was from a Project other than a Primary Facility, then Seller shall provide Buyer Notice identifying such Project by the twenty-fifth (25^{th}) Business Day following the end of such calendar month.

8.3 Governing Law

(a) Notwithstanding any provision to the contrary in the EEI Agreement, the Governing Law applicable to this Transaction is set forth in Section 8.3(b) below. This Section 8.3 does not change the Governing Law applicable to any other Transaction entered into between the Parties under the EEI Agreement.

(b) Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

For the purposes of Section 8.3(b) above, the words "party" and "parties" shall have the meaning ascribed to them in the first paragraph of this Confirmation, and the word "agreement" shall mean the term "Agreement" as defined in the first paragraph of this Confirmation.

ARTICLE 9
CONFIDENTIALITY

9.1 Without limiting the provisions of Section 10.11 of the EEI Agreement, each of Buyer and Seller may disclose the following information regarding this Confirmation:

(a) Party names;
(b) Resource;
(c) Term;
(d) Project location(s);
(e) Capacity of each facility designated as the Project;
(f) The fact that a facility designated as the Project is on-line and delivering;
(g) Delivery Point; and
(h) The quantity of Product expected or actually delivered under this Confirmation.

Except for disclosures to comply with any applicable regulation, rule, or order of the CPUC, Federal Energy Regulatory Commission, CEC, or other Governmental Authorities, each Party shall provide Notice of any disclosure made pursuant to this Article 9 to the other Party.

ACKNOWLEDGED AND AGREED TO:

PACIFIC GAS AND ELECTRIC COMPANY, a California corporation	[**BUYER, a (*include place of formation and business type*)**], **by its duly authorized officers**
Signature: ______________________	Signature: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

APPENDIX A to
EEI Master Power Purchase and Sale Agreement
Short Term Sales Confirmation

PROJECT

Name of Facility	Resource	Capacity (MW)	CEC RPS ID	WREGIS GU ID	Host Balancing Authority

APPENDIX B

FORM OF LETTER OF CREDIT

Issuing Bank Letterhead and Address

STANDBY LETTER OF CREDIT NO. XXXXXXXX

Date: ***[insert issue date]***

Beneficiary: Pacific Gas and Electric Company

77 Beale Street, Mail Code B28L
San Francisco, CA 94105
Attention: Credit Risk Management

Applicant: [Insert name and address of Applicant]

Letter of Credit Amount: ***[insert amount]***

Expiry Date: ***[insert expiry date]***

Ladies and Gentlemen:

By order of ***[insert name of Applicant]*** ("Applicant"), we hereby issue in favor of Pacific Gas and Electric Company (the "Beneficiary") our irrevocable standby letter of credit No. ***[insert number of letter of credit]*** ("Letter of Credit"), for the account of Applicant, for drawings up to but not to exceed the aggregate sum of U.S. $ ***[insert amount in figures followed by (amount in words)]*** ("Letter of Credit Amount"). This Letter of Credit is available with ***[insert name of issuing bank, and the city and state in which it is located]*** by sight payment, at our offices located at the address stated below, effective immediately, and it will expire at our close of business on ***[insert expiry date]*** (the "Expiry Date").

Funds under this Letter of Credit are available to the Beneficiary against presentation of the following documents:

1. Beneficiary's signed and dated sight draft in the form of Exhibit A hereto, referencing this Letter of Credit No. ***[insert number]*** and stating the amount of the demand; and

2. One of the following statements signed by an authorized representative or officer of Beneficiary:

   A. "Pursuant to the terms of that certain EEI Power Purchase and Sale Agreement (the "Agreement"), dated ***[insert date of the Agreement]***, between Beneficiary and ***[insert name of Seller under the Agreement]*****,** or any Confirmation thereunder or related thereto**,** Beneficiary is entitled to draw under Letter of Credit No. ***[insert number]*** amounts owed by ***[insert name of Seller under the Agreement]*** under the Agreement; or

   B. "Letter of Credit No. ***[insert number]*** will expire in thirty (30) days or less and ***[insert name of Seller under the Agreement]*** has not provided replacement security acceptable to Beneficiary.

Special Conditions:

1. Partial and multiple drawings under this Letter of Credit are allowed;
2. All banking charges associated with this Letter of Credit are for the account of the Applicant;

3. This Letter of Credit is not transferable; and
4. The Expiry Date of this Letter of Credit shall be automatically extended without a written amendment hereto for a period of one (1) year and on each successive Expiry Date, unless at least sixty (60) days before the then current Expiry Date we notify you by registered mail or courier that we elect not to extend the Expiry Date of this Letter of Credit for such additional period.

We engage with you that drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored upon presentation, on or before the Expiry Date (or after the Expiry Date in case of an interruption of our business as stated below), at our offices at ***[insert issuing bank's address for drawings]***.

All demands for payment shall be made by presentation of original drawing documents and a copy of this Letter of Credit; or by facsimile transmission of documents to ***[insert fax number]***, Attention: ***[insert name of issuing bank's receiving department]***, with original drawing documents and a copy of this Letter of Credit to follow by overnight mail. If presentation is made by facsimile transmission, you may contact us at ***[insert phone number]*** to confirm our receipt of the transmission. Your failure to seek such a telephone confirmation does not affect our obligation to honor such a presentation.

Our payments against complying presentations under this Letter of Credit will be made no later than on the sixth (6th) banking day following a complying presentation.

Except as stated herein, this Letter of Credit is not subject to any condition or qualification. It is our individual obligation, which is not contingent upon reimbursement and is not affected by any agreement, document, or instrument between us and the Applicant or between the Beneficiary and the Applicant or any other party.

Except as otherwise specifically stated herein, this Letter of Credit is subject to and governed by the *Uniform Customs and Practice for Documentary Credits, 2007 Revision,* International Chamber of Commerce (ICC) Publication No. 600 (the "UCP 600"); provided that, if this Letter of Credit expires during an interruption of our business as described in Article 36 of the UCP 600, we will honor drafts presented in compliance with this Letter of Credit, if they are presented within thirty (30) days after the resumption of our business, and will effect payment accordingly.

The law of the State of New York shall apply to any matters not covered by the UCP 600.

For telephone assistance regarding this Letter of Credit, please contact us at ***[insert number and any other necessary details]***.

Very truly yours,

[insert name of issuing bank]

By: ______________________________
Authorized Signature

Name: ________***[print or type name]***________

Title: ________***[print or type title]***________

[Note: All pages must contain the Letter of Credit number and page number for identification purposes.]

EXHIBIT A -- SIGHT DRAFT to

APPENDIX B -- Form of Letter of Credit

TO
[INSERT NAME AND ADDRESS OF PAYING BANK]

AMOUNT: $________________________ DATE: __________________________

AT SIGHT OF THIS DEMAND PAY TO THE ORDER OF PACIFIC GAS AND ELECTRIC COMPANY THE AMOUNT OF U.S.$________(______________ U.S. DOLLARS)

DRAWN UNDER ***[INSERT NAME OF ISSUING BANK]*** LETTER OF CREDIT NO. XXXXXX.

REMIT FUNDS AS FOLLOWS:

[INSERT PAYMENT INSTRUCTIONS]

DRAWER

BY: ________________________________
NAME AND TITLE

APPENDIX J

Framework for Assessing Potential Sales of Surplus RPS Volumes

August 8, 2016

Appendix J – Framework for Assessing Potential Sales of Surplus Renewables Portfolio Standard Volumes

This Appendix describes Pacific Gas and Electric Company's ("PG&E") proposed framework for assessing whether to hold or sell surplus Renewables Portfolio Standard ("RPS") volumes ("Sales Framework"). [redacted]

[redacted]

[redacted]

[redacted] 1 [redacted]

[redacted]

---

1 [redacted]

[redacted]

[redacted]

[redacted]

[redacted][2][redacted]

[redacted]

[redacted]

1. [redacted][3][redacted]

2. [redacted]

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2 [redacted]

3 [redacted]

3. [redacted][4] [redacted]

[redacted]

- [redacted]

4 [redacted]

[redacted]

- [redacted]
- [redacted]

APPENDIX A

Redline Showing Changes in August 8, 2016 Draft RPS Plan Compared to January 14, 2016 Final 2015 RPS Plan ~~Compared to August 4, 2015 Draft RPS Plan~~

~~January 14~~August 8, 2016

~~Public~~

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

~~FINAL 2015~~DRAFT 2016 RENEWABLE ENERGY PROCUREMENT PLAN

~~JANUARY 14~~AUGUST 8, 2016

~~Public~~

PUBLIC VERSION

PG&E ®

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LIST OF APPENDICES

Pacific Gas and Electric Company ("PG&E") respectfully submits its ~~Final 2015~~Draft 2016 Renewables Portfolio Standard ("RPS") Plan ("~~2015~~2016 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed ~~by~~in the ~~Commission in Decision ("D.") 15-12-025.~~*Assigned Commissioner and Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans* issued on May 17, 2016 ("Ruling").[1] PG&E's ~~2015~~2016 RPS Plan includes a summary of key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the~~ *Assigned Commissioner's Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewable Portfolio Standard Procurement Plans* ("ACR") issued in this proceeding on May 28, 2015~~ Ruling.[2]

~~1~~1. Summary of Key Issues

~~1.1~~1.1. PG&E's RPS Position

PG&E projects that under ~~both~~ the ~~current~~ 33% RPS by 2020 target, ~~as well as a 40% by 2024 scenario~~and an assumed "straight-line" trajectory implementing the Senate Bill ("SB") 350 target of 50% RPS by 2030, it is well-positioned to meet its RPS compliance requirements for the second (2014-2016~~) and~~), third (2017-2020), and fourth (2021-2024) compliance periods and will not have incremental ~~procurement~~RPS physical need until at least ~~2022. Under the current 33% RPS target,~~2026.[3] PG&E

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[1] Administrative Law Judge ("ALJ") Mason sent an email on June 8, 2016 allowing Investor-Owned Utilities ("IOU"), Small Utilities, Energy Service Providers and Community Choice Aggregators ("CCA") until August 8, 2016 to file proposed annual RPS Procurement Plans.

[2] *See* ~~ACR~~Ruling, pp. ~~8~~3-20.

[3] PG&E announced in June that it had entered into a Joint Proposal with a number of parties for the orderly retirement of the Diablo Canyon Power Plant and its replacement with greenhouse gas ("GHG")-free resources, possibly including RPS resources procured through an all-source Request for Offer ("RFO") framework and a voluntary 55% RPS commitment. PG&E intends to file an application requesting Commission approval of specific elements of the Joint Proposal, including elements related to GHG-free resource procurement. However, because the Commission has not yet reviewed and approved the

projects that it will have incremental RPS procurement need beginning in [redacted], after applying banked volumes of excess procurement ("Bank") beginning in [redacted]~~. Under the 40% RPS by 2024 scenario, PG&E projects that it will have incremental procurement need beginning in~~ [redacted]~~, after applying Bank beginning in~~ [redacted]~~. In both situations,~~. Changes to PG&E's near-term RPS position and increases in PG&E's forecasted surplus RPS volume have been driven primarily by declining retail sales projections.

Given its forecasted position, PG&E has developed a framework to assess whether to hold or sell excess RPS volumes. The proposed framework is summarized in Sections 1.4 and 19 below, and described in more detail in Appendix J. Based on PG&E's current load forecast and RPS position, applying the proposed framework would lead PG&E to hold one or more solicitations for sales of surplus bankable, bundled RPS volumes in 2017. PG&E anticipates additional steady, incremental ~~long-term~~sales or procurement in subsequent years to ~~avoid the need to procure large volumes in any single year to meet compliance needs~~manage its RPS position and maintain adequate minimum Bank levels. Should PG&E engage in RPS sales, its position will be updated in subsequent RPS Plans to reflect an earlier procurement need year.

~~1.2~~1.2. PG&E ~~Will~~Proposes Not to Hold a ~~Request for Offers~~Solicitation to Procure in ~~2015~~2016

Given its current RPS compliance position, PG&E ~~will~~is proposing in this 2016 RPS Plan not to hold an RPS procurement solicitation ~~in 2015~~for the 2016 solicitation cycle. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for ~~future~~procurement solicitations in ~~next year's~~future RPS ~~Plan~~Plans. Although many factors could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS

Joint Proposal, the GHG-free resource elements of the Joint Proposal are not included in this draft of the 2016 RPS Plan.

contracts, its owned RPS-~~-~~eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-~~-~~term RPS requirements. Additionally, even without an RPS solicitation, PG&E expects to continue to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs in ~~2016~~2017.[4] PG&E will seek permission from the Commission to procure any amounts other than amounts separately mandated by the Commission ~~(*i.e.*, Feed-In Tariff ("FIT") and RAM)~~ during the time period covered by the ~~2015~~2016 solicitation cycle. ~~In 2016,~~

PG&E does not support expansion of existing mandated programs or additional new mandated programs.[5] Mandated procurement programs do not optimize costs for customers because they restrict flexibility and optionality to achieve the RPS targets by mandating procurement through a potentially less efficient and more costly manner. PG&E supports a technology-neutral procurement process, in which all RPS-eligible technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

PG&E will continue to annually reassess its Renewable Net Short ("RNS") position and determine its updated procurement needs. PG&E's ~~decision to~~proposal not to hold a ~~2015~~2016 RPS procurement solicitation is consistent with ~~a proposal~~ past proposals to not hold RPS solicitations made by PG&E and San-~~-~~Diego Gas & Electric Company ("SDG&E") in ~~its 2014~~their respective 2015 RPS ~~Plan, and~~Plans, which were approved by the Commission given ~~SDG&E's~~ lack of RPS need.[6]

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4 Mandated programs include Renewable ~~Auction Mechanism ("RAM"), Renewable~~ Market Adjusting Tariff ("ReMAT"), Bioenergy Renewable Auction Mechanism ("BioRAM"), and Bioenergy Market Adjusting Tariff ("BioMAT"). In addition, while not pursuant to the RPS mandate, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program.

5 PG&E also notes that on January 22, 2016, it filed a Petition to Modify D.14-11-042 to eliminate the requirement that PG&E conduct solicitations in 2016 and 2017 for additional photovoltaic ("PV") resources resulting from PG&E's closed PV Program. The petition for modification is still pending at the Commission.

6 D.~~14-11-032, p. 32~~15-12-025, pp. 35, 62, Ordering ~~Paragraph 17~~Paragraphs 8, 9.

~~1.3 Consideration~~Maintaining Some Level of ~~Higher RPS Targets Should Be Integrated With Broader State Greenhouse Gas Goals~~

~~California's RPS has played, and will continue to play, an important role in lowering electric sector greenhouse gas ("GHG") emissions and meeting the state's clean energy goals. PG&E supports maintaining the existing requirements that load-serving entities ("LSE") provide a minimum of 33% RPS in 2020, moving towards 50% in 2030. However, PG&E believes California's clean energy policy should be centered on achieving the most cost-effective GHG reductions needed to meet the Governor's 2030 goal of emissions that are 40% below 1990 levels.[7]~~

~~Before taking any action that would increase the RPS requirements, the Commission should consider how the RPS program fits within a comprehensive GHG policy framework built to achieve emissions reductions through a combination of actions, as opposed to potentially inefficient carve-out mechanisms.[8] Renewable energy policy should be more completely aligned with this broader policy context in order to ensure that GHG reduction targets are achieved in an integrated and economically efficient manner. Rather than reflexively raise the RPS targets, the CPUC should adopt a strategy focused on flexibility, equitable rules for all LSEs, affordability, and market and system stability.[9]~~

~~1.4 Renewable Portfolio Growth Increases Customer Rate Impacts~~

~~As a part of this RPS Plan, PG&E is providing historic and forecasted RPS cost and rate information. From 2003-2015, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. The costs of the RPS Program have~~

~~7 Office of California Governor Edmund G. Brown, Executive Order 4-29-2015 (available at http://gov.ca.gov/news.php?id=18938).~~

~~8 For further discussion of the cost impacts of mandated procurement programs, see Section 13.3.~~

~~9 For further discussion, see PG&E's opening and reply comments in response to *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program (R.15-02-020)* filed on March 26, 2015 and April 6, 2015, respectively.~~

~~already and will continue to impact customer bills. From 2003-2016, PG&E estimates its annual rate impact from RPS procurement has increased from 0.7 cents per kilowatt-hour ("¢/kWh") in 2003 to an estimated 3.5¢/kWh in 2016.[10] The growth in rates due to RPS procurement costs will continue to increase through 2020, as the average rate impact is forecasted to increase to 3.9¢/kWh, or approximately $2.3 billion. Further detail regarding RPS costs is provided in Section 13 and the annual rate impact of forecasted procurement is detailed in Table 2 of Appendix D.~~

~~To address these rate impacts, PG&E's procurement strategy attempts to minimize cost and maximize value to customers, while satisfying the RPS program requirements. To accomplish this goal, PG&E promotes competitive processes to procure incremental RPS volumes, strategically uses its Bank, and avoids long-term over-procurement.~~

~~As described above, a more integrated GHG policy framework that enables LSEs to adapt to changing needs, costs, and circumstances and manage the integration of variable resources would provide additional opportunities to lower customer costs. New technologies will emerge and the mix and cost-effectiveness of GHG emissions reduction strategies will undoubtedly evolve over the next several years. PG&E believes that a more flexible implementation of the RPS Program that allows LSEs to optimize a portfolio of different GHG reduction strategies would facilitate meeting the State's environmental goals at the lowest possible costs and best portfolio fit, and provide the maximum benefits to customers. Similarly, as discussed in Section 13.3, mandated procurement programs within the RPS reduce the program's efficiency while increasing costs.~~

~~10 "Annual Rate Impact" should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.~~

~~1.5~~1.3. ~~PG&E's~~ Bank Is Necessary to Ensure PG&E's Long-Term Compliance and Customer Affordability

PG&E views ~~its~~ having a minimum Bank as necessary to: (1)~~-~~ mitigate risks associated with ~~variability~~uncertainty in load; (2) protect against project failure or delay exceeding forecasts; and (3)~~ avoid intentional over-procurement above the 33% RPS target by managing~~ manage year-to-year generation variability from ~~performing~~ RPS resources. The Bank allows PG&E to mitigate the need to procure additional RPS products at potentially high market prices in order to meet near-term compliance deadlines. ~~With an adequate Bank, PG&E aims to minimize customer cost by having the flexibility not to procure in "seller's market" situations.~~ More information on forecasted Bank size and minimum Bank levels ~~under both 33% and 40% RPS~~ is provided in Section 7~~-~~ below.

~~PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E's RNS, future RPS cost projections, and assessment of the current Renewable Energy Credit ("REC") market do not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.~~

~~1.6 RPS Rules Should Be Applied Consistently and Equitably Across All LSEs~~

~~PG&E's long-term position is a forecast based on a number of assumptions, including a certain amount of load departure due to Community Choice Aggregation ("CCA") and distributed generation growth. While it is possible that this forecasted load departure may not fully materialize or occur at the rate assumed in the forecast, PG&E's forecast is a reasonable scenario based on current trends. Under the existing percentage-based RPS targets, any departure of PG&E's load to CCAs naturally results in both a reduction of PG&E's required RPS procurement quantities and a corresponding increase in RPS procurement by CCAs. Thus, CCAs will be required to shoulder an increasing portion of the State's RPS procurement goals. The consistent~~

~~and equitable application of all RPS rules and requirements to all Commission-jurisdictional LSEs, including CCAs and Energy Service Providers ("ESPs"), will help to ensure that all LSEs are helping California achieve its ambitious renewable energy goals.~~

1.4. PG&E Proposes a Framework to Assess Potential Sales of Excess RPS Volumes

PG&E's forecasted RPS position predicts a higher cumulative Bank than its calculated minimum Bank. While the Bank holds value as an instrument for future RPS compliance, PG&E has developed a framework to assess whether to hold or sell excess RPS volumes, which will allow PG&E to rebalance its RPS portfolio to better align its RPS position with its RPS need. PG&E is requesting Commission review and approval of this framework as a part of the 2016 RPS Plan. If approved, the proposed framework will be used to determine future sales of bankable RPS volumes. The details of PG&E's sales framework are discussed in Section 19 and Appendix J. Based on the existing inputs to this framework, PG&E expects to conduct one or more solicitations in 2017 for short-term sales of bundled RPS volumes. PG&E anticipates selling short-term products in 2017, and may consider longer-term offers in the future.

1.5. Any Additional Procurement Due to the Governor's Emergency Proclamation on Tree Mortality Should Be Based on a Clear Demonstration of Need

PG&E remains committed to working closely with the Commission and the state to identify policy solutions and uses for biomass material that is the result of the drought and bark beetle-related tree mortality. While PG&E has been partnering with the state to respond to Governor Brown's Emergency Proclamation on Tree Mortality ("Emergency Proclamation"),[11] PG&E does not have a need to procure RPS resources

[11] Governor Brown issued the Emergency Proclamation on October 30, 2015 to address the significant drought-related tree mortality concerns in California.

to meet our customers' needs, and strongly believes that any BioRAM procurement costs must be recovered from all benefitting customers.

Any mandated Emergency Proclamation-related procurement should first be based on a clear demonstration of need. Outside of BioRAM, PG&E is the only IOU currently procuring biomass in the state. If additional Emergency Proclamation-related procurement is found necessary, all load-serving entities ("LSE") must either be required to participate or costs must be allocated to all benefitting customers in California on a fully non-bypassable basis.[12] Finally, in order to address the statewide emergency, PG&E believes that any additional Emergency Proclamation-related procurement should be of short-term duration and require the use of high-hazard fuel.

~~2~~2. Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

PG&E's portfolio forecast and procurement decisions are influenced by ongoing legislative and regulatory changes to the RPS Program. ~~The following is a description of recent changes to the RPS Program that have impacted PG&E's RPS procurement~~The following section summarizes recent legislative and regulatory developments that may impact PG&E's RPS Program. Specifically, this section addresses: (1) the adoption and implementation of SB 350; (2) implementation of bioenergy legislation and directives; and (3) outstanding cost containment issues.

~~2.1~~2.1. ~~Commission~~Adoption and Implementation of Senate Bill ~~2 (1x)~~350

On October 7, 2015, Governor Brown signed SB 350, known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increases the RPS target from 33% in 2020 to 50% in 2030. On April 15, 2016, ALJ Simon issued a ruling to begin implementation of SB 350 provisions relating to RPS

[12] PG&E and Southern California Edison Company ("SCE") filed a *Petition For Modification Of Decision 10-12-048* in Rulemaking ("R.") 08-08-009 on April 19, 2016 regarding the allocation of costs related to the Emergency Proclamation. This petition for modification is still pending at the Commission.

procurement, including establishing post-2020 compliance periods, and changes to the banking provisions and long-term procurement requirements in 2016.[13]

Commission action on SB 350 implementation, as well as other remaining issues identified in R.15-02-020, may impact PG&E's procurement need and actions going forward. PG&E notes that its 2016 RPS Plan reasonably reflects aspects of SB 350, including a "straight-line" RPS target trajectory from 33% to 50%. However, these assumptions should be treated as preliminary as the Commission has not yet issued a final decision(s) on SB 350 implementation.

One specific aspect of SB 350 requires some additional discussion. SB 350 added a 65% long-term contracting requirement in California Public Utilities Code ("Pub. Util. Code") Section 399.13(b).[14] The Commission has not yet adopted implementation rules regarding this requirement. However, Section 399.13(a)(4)(B)(iii) provides that that "[i]f a retail seller notifies the commission that it will comply with the [minimum long-term requirement] for the compliance period beginning January 1, 2017, the [new RPS banking rules set forth in the same subdivision] shall take effect for that retail seller for that compliance period." Although the Commission has not yet implemented this new statutory language by specifying the manner or process by which a retail seller must notify the Commission of its intent to comply early with the minimum long-term requirements, PG&E intends this 2016 RPS Plan to provide such notice if the Commission ultimately determines that the notice should be provided as part of the annual RPS Plan submissions.

PG&E will revisit these assumptions in future RPS Plans once the Commission provides final guidance on the manner or process for which a retail seller is to provide

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13 *Administrative Law Judge's Ruling Requesting Comments on Implementation of Elements of Senate Bill 350 Relating to Procurement under the California Renewables Portfolio Standard*, issued April 15, 2016.

14 All further statutory references are to the California Pub. Util. Code unless otherwise noted.

notice of its intent to comply early with the minimum long-term contract provisions to the Commission.

2.2. Implementation of Bioenergy Legislation and Directives

The Emergency Proclamation, which was described above in Section 1.5, is targeted at multiple state agencies to identify High Hazard Zones (HHZ) and facilitate wildfire mitigation across the state. The Emergency Proclamation specifically identifies actions for the Commission, such as expediting new contract execution through BioMAT or a new targeted procurement mechanism. The Commission has responded by considering changes to the BioMAT program, as well as initiating a new procurement program for bioenergy facilities. PG&E briefly describes these developments below.

2.2.1. BioMAT

On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure 250 megawatts ("MW") in total of new small-scale bioenergy projects 3 MW or less through the Feed-In Tariff ("FIT") Program. The total IOU program MWs are allocated into three technology categories: 110 MW for biogas from wastewater plants and green waste; 90 MW for dairy and other agriculture bioenergy; and 50 MW for forest waste biomass. On December 18, 2014, the Commission issued Decision ("D.") 14-12-081 to implement SB 1122 and required the IOUs to file a tariff and contract for SB 1122 eligible generation. ~~Senate Bill ("SB") 2 (1x), enacted in April 2011 and effective as of December 11, 2011, made significant changes to the RPS Program, most notably extending the RPS goal from 20% of retail sales of all California investor-owned utilities ("IOUs"), ESPs, publicly owned utilities, and CCAs by the end of 2010, to a goal of 33% of retail sales by 2020. The Commission issued an Order Instituting Rulemaking to implement SB 2 (1x) in May 2011 and has subsequently issued a number of key decisions implementing certain "high priority" issues needed to implement the complex provisions of SB 2 (1x). In February 2015, the Commission opened a new Rulemaking (R.) 15-02-020 to address remaining issues from this earlier~~

~~proceeding, as well as other elements of the ongoing administration of the RPS Program. Commission action on remaining and new key issues may impact PG&E's procurement need and actions going forward, notwithstanding the forecasts and projections included in this Plan.~~

~~Key Commission decisions issued to date implementing SB 2 (1x) include D.11-12-052 which defined portfolio content categories ("PCC"), D.11-12-020 which outlined compliance period targets for the 33% RPS target, and D.12-06-038 which implemented changes to the RPS compliance rules for retail sellers, including treatment of prior procurement to meet RPS obligations for both the 20% and 33% RPS Programs. D.12-06-038 also adopted rules on calculating the RPS Bank, meeting the portfolio balance requirements, and for reporting annually to the Commission on RPS procurement. Finally, on December 4, 2014, the CPUC adopted D.14-12-023 setting RPS compliance and enforcement rules under SB 2 (1X).~~

The IOUs filed their proposed contract and tariff on February 6, 2015, which were approved with modifications in D.15-09-004. PG&E's SB 1122 Program (BioMAT) began accepting participants on December 1, 2015 and the first program period (auction) was held on February 1, 2016. The second program period (auction) was held on April 1, 2016. The Commission is currently considering changes to the BioMAT Program, including higher contract prices for facilities that use forest fuel from HHZs, fuel verification requirements and clarification of the existing BioMAT interconnection requirements.

2.2.2. BioRAM

To further address the Emergency Proclamation, the Commission initiated a new procurement program for bioenergy facilities (BioRAM) which requires the IOUs to procure energy from bioenergy facilities using forest fuel supplied from wildfire HHZs. Facilities participating in BioRAM are required to meet annual minimum levels of fuel source from HHZs, starting at 40% in 2016 and increasing to 80% in 2020 and beyond.

BioRAM has a minimum program size of 50 MW; PG&E's share is a minimum of 20 MW. Before beginning the program, the IOUs were required to modify their existing Renewable Auction Mechanism ("RAM") contract language in order to specifically address the BioRAM considerations.[15] PG&E launched the BioRAM solicitation on June 28, 2016 with offers due on July 28, 2016. More details related to PG&E's biomass portfolio and its response to the Emergency Proclamation is discussed in Section 18 of the 2016 RPS Plan.

On April 19, 2016, PG&E and SCE filed a joint Petition for Modification of D.10-12-048, which authorized the RAM Program, to specify that any contract-related costs incurred as part of the implementation of the Emergency Proclamation be allocated to all benefitting parties (*i.e.*, bundled, CCA, and Direct Access ("DA") customers) using a new Non-Bypassable Charge (a "BioRAM NBC") or, alternatively, the Cost Allocation Mechanism. The Petition for Modification is still pending at the Commission.

~~2.2~~2.3. Cost Containment

When California's legislature passed SB~~-~~ 2~~-~~ (1x), it required the ~~CPUC~~Commission to develop a limitation on total RPS costs for each electrical corporation. The legislature specified that the cost limitation must prevent the 33% RPS target from causing "disproportionate rate impacts." SB 350 modified certain criteria regarding cost containment, including allowing for the consideration of indirect costs in setting the cost cap.[16] If PG&E exceeds the Commission-approved cost cap, it may refrain from entering into new RPS contracts and constructing RPS-eligible facilities unless additional procurement can be undertaken with only "de minimis" rate impacts.

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[15] On April 7, 2016, PG&E and the other IOUs filed advice letters with the Commission with their proposed contract modifications and on June 1 and June 3, PG&E filed two supplemental advice letters with an updated contract and solicitation protocol. The Commission issued a Disposition Letter approving PG&E's advice letter and supplemental advice letters on June 14, 2016.

[16] Cal. Pub. Util. Code §399.15(c).

PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can have on customers, PG&E strongly supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation ("PEL") that both informs procurement planning and decisions, and promotes regulatory and market certainty. ~~PG&E urges the Commission to finalize the PEL as soon as~~ Implementation of the PEL has been ongoing at the Commission since SB 2 (1X) was passed five years ago. During that time, the Commission and stakeholders have taken actions related to developing a cost containment proposal, including holding a workshop in November 2013 to discuss Energy Division staff's PEL proposal, alternate proposals, and implementation details, as well as issuing and seeking comments on a revised proposal in February 2014. PG&E urges the Commission to finalize the PEL as soon as possible.

~~**2.3 Implementation of Bioenergy Legislation**~~

~~On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure 250 megawatts ("MW") in total of new small-scale bioenergy projects 3 MW or less through the FIT Program. The total IOU program MWs are allocated into three technology categories: 110 MW for biogas from wastewater plants and green waste; 90 MW for dairy and other agriculture bioenergy; and 50 MW for forest waste biomass. The allocation of MWs by project type for each IOU, as well as the program design, is being determined by the Commission in proceedings currently underway. PG&E has worked with the Commission and stakeholders in order to ensure that the SB 1122 program is implemented in a way that balances the needs of the bioenergy industry with clear cost containment mechanisms that protect customers from excessive costs. On December 18, 2014, the Commission issued D.14-12-081 to implement SB 1122 and required the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015, which were approved with modifications in D.15-09-004. PG&E's SB 1122 program~~

~~("BioMAT") began accepting participants on December 1, 2015 and the first program period will start on February 1, 2016.~~

~~2.4 Senate Bill 350~~

~~On October 7, 2015, Governor Brown signed SB 350 (de Leon), known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increases the RPS target from 33% in 2020 to 50% in 2030. The Commission will begin implementation of SB 350 in 2016.~~

~~3~~3. Assessment of RPS Portfolio Supplies and Demand

~~3.1~~3.1. Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's ~~33~~50% RPS target. PG&E is currently required to procure the following quantities of RPS-eligible products:

- 2011-2013 (First Compliance Period): 20% of the combined bundled retail sales.
- 2014-2016 (Second Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
- 2021~~ and beyond: 33~~-2024: 40% of combined bundled retail sales ~~in 2021~~by end of period.[17]

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17 ~~SB 350 establishes the following new multi-year RPS compliance period: 40% by the end of 2021-2024; 45% by the end of 2025-2027; and 50% by the end of 2028-2030 and each year thereafter.~~ For SB 350 compliance periods, PG&E is assuming a "straight line" compliance pathway between the end of compliance period targets established in SB 350, as this is consistent with the current assumptions for how the target is calculated.

- 2025-2027: 45% of combined bundled retail sales by end of period.
- 2028-2030: 50% by end of period and each year thereafter.

Based on preliminary results presented in Appendix C.~~2a~~2, PG&E delivered ~~27.0%~~ 29.5% of its power from RPS-eligible renewable sources in ~~2014~~2015.

As described more fully in Section 7 and reported in the current RNS calculations in Appendix C.~~2a~~2, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements for the second (2014-2016~~) and~~), third (2017-2020), and fourth (2021-2024) compliance periods. Under the ~~33~~50% RPS by 2030 target, PG&E projects that it will not have incremental RPS physical need until at least 2026, and a procurement need ~~until at least 2022, with need~~ beginning in [redacted]~~,~~ after applying the Bank beginning in [redacted]. Should PG&E engage in RPS sales, its position will be updated in subsequent RPS Plans to reflect an earlier procurement need year.

~~Under a 40% RPS scenario, PG&E modeled the same trajectory through 2020 as described above, but modeled the following RPS requirements starting in 2021:~~

- ~~33% of combined bundled retail sales in 2021;~~
- ~~37% of combined bundled retail sales in 2022;~~
- ~~37% of combined bundled retail sales in 2023; and~~
- ~~40% of combined bundled retail sales in 2024 and each year thereafter.~~

~~For this scenario, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E projects that it is well-positioned to meet its RPS compliance requirements for the second (2014-2016) and third (2017-2020) compliance periods. PG&E projects that it will have incremental procurement need beginning in~~ [redacted]~~, after applying its Bank towards its physical net short beginning in~~ [redacted]~~.~~~~[18]~~

~~[18] This projection includes future volumes from mandated programs, such as the RAM and FIT Programs.~~

~~3.2~~3.2. Supply

~~3.2.1~~3.2.1. Existing Portfolio

PG&E’s existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes ~~over~~approximately 8,000~~-~~ MW of active projects, ranging from utility-owned solar and small hydro generation to long~~-~~-term RPS contracts for large wind, geothermal, solar, and biomass to small FIT contracts for solar ~~photovoltaic (“~~PV~~”),~~, biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 6 and 7.

As described in further detail in Section 7.1, for the ~~2015~~2016 RPS Plan, PG&E assumes a volumetric expected success rate for all executed in-development projects in its RPS portfolio of ~~approximately 99~~100% of total contracted volumes.~~ This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, and 87% in PG&E's 2014 RPS Plan.~~[19] This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations. ~~While PG&E has continued to see a general trend towards higher project success rates, the change in its success rate assumption from 2014 to 2015 (from 87% to 99%) reflects the recent removal of several projects from PG&E's portfolio due to contract terminations and an update to the "Closely Watched" category described in Section 6.~~

Consistent with the project trends reported in its ~~2014~~2015 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have continued to increase many projects' cost-effectiveness, contributing to their eventual completion. Progress in the siting and permitting of projects has also supported PG&E's sustained high success rate. As described in more detail in ~~Section 3~~this section, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

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19 PG&E's success rate discussed is more reflective of the success rate of its overall portfolio, and so this percentage does not convey that PG&E has no projects failing. Specifically, since almost all of PG&E's in-development projects are volumes procured through mandated programs with set targets, any projects that fail will be replaced through future solicitation rounds. Therefore, the effect on PG&E's portfolio is that the amount of volumes projected has a very high project success rate, given that any failed project will be replaced with a new project, until the volumes come online.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in ~~Sections 5 and 6~~the remainder of Section 3 and Section 4.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section ~~6~~4, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted~~,[20] although these resources are encouraged to bid into PG&E's future competitive solicitations~~.

~~3.2.2~~3.2.2. Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program that allows PG&E customers to meet up to 100% of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission ~~adopted~~issued D.15-01-051 implementing a GTSR framework, approving the IOUs' applications with modifications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment.

Pursuant to D.15-01-051, PG&E ~~has~~ submitted several advice letters related to implementation of the GTSR ~~program that are currently pending before the Commission.~~Program. In February 2015, PG&E filed an advice letter containing its plans for advance procurement for the GTSR Program and identifying the eligible census tracts for environmental justice projects in its service territories.[21] In May 2015,

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~~20 Although the physical net short calculations in PG&E's deterministic model do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, the stochastic model can re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive. PG&E's deterministic and stochastic models are described in more detail below in Section 6.~~

21 PG&E Advice Letter 4593-E (supplemented March 25, 2015).

together with ~~Southern California Edison Company~~SCE and SDG&E, PG&E submitted a Joint Procurement Implementation Advice Letter, addressing each utility's plans for ongoing GTSR Program procurement and RPS resource and Renewable Energy Credit ("REC") separation and tracking.[22] ~~Concurrently~~The Joint Procurement Implementation Advice Letter and supplemental filing became effective on November 20, 2015.

Concurrent with the Joint Procurement Implementation Advice Letter, PG&E filed a Marketing Implementation Advice Letter[23] and a Customer-Side Implementation Advice Letter[24] with details regarding implementation. The Marketing Implementation Advice Letter and supplemental filing became effective on October 1, 2015 and the Customer-Side Advice Letter and supplemental filing became effective on November 20, 2015.

In addition, to accommodate GTSR procurement, PG&E filed Advice Letter 4605-E to change its RAM 6 Power Purchase Agreements ("PPA") and ~~Request for Offer (~~"RFO~~")~~ instructions, consistent with the minimum goals for 2015 identified in D.15~~-~~-01~~-~~-051.[25] Advice Letter 4605-E was approved via a Disposition Letter dated June 17, 2015.

~~The~~ On July 7, 2015, PG&E launched its RAM 6 solicitation seeking 50 MW for the GTSR Program. In December and January 2016, PG&E executed eight GTSR Program PPAs for a total of 52.75 MW, which were filed for approval as part of Advice Letter 4780-E on January 22, 2016. The facilities pursuant to these PPAs are currently under development and their status is included in the Project Development Status Update section (see Chapter 4).

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22 Advice Letter 4637-E.

23 Advice Letter 4638-E.

24 Advice Letter 4639-E.

25 *See* D.15-01-051, Section 4.2.4, pp. 25-28.

TABLE 3-1
PROGRESS OF GTSR PROGRAM PROCUREMENT

Procured Capacity (as of May 2016)	Available Capacity (MW)	GT Procured (MW)	ECR Procured (MW)	Remaining Capacity (MW)
Unrestricted Other Community	207	50.75 44.50 6.25	0	156.25
EJ Reservation	45	2	0	43
City of Davis	20	0	0	20
Totals	**272**	**52.75**	**0**	**219.25**

In January 2016, PG&E's GTSR Program opened for enrollment under the program name "PG&E's Solar Choice." On March 15, 2016, PG&E filed its 2015 Green Tariff Shared Renewables Annual Report with the Commission.

On May 19, 2016, the Commission issued D.16-05-006 regarding Phase IV issues in the GTSR proceeding. This decision addressed participation of Enhanced Community Renewables ("ECR") projects in RAM solicitations and made refinements to the GTSR Program. Later this year, PG&E will ~~impact~~hold its first ECR RFO using the RAM solicitation, pursuant to D.16-05-006.

The GTSR Program impacts PG&E's RPS position in two ways: (1) ~~PG&E's~~ RPS supply may be affected; and (2) ~~PG&E's~~ retail sales will be reduced corresponding to program participation. ~~The GTSR decision~~D.15-01-051 permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. ~~PG&E will implement~~In this case, those volumes procured for GTSR would then be added to PG&E's RPS portfolio, even if PG&E had no

RPS need. PG&E is developing tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff ~~programs. Because the GTSR implementation Advice Letters discussed above[26] have not yet been approved, PG&E's RNS calculation submitted with this RPS Plan does not reflect the impact of GTSR on PG&E's RPS position. Due to the relatively small volumes of the GTSR interim pool compared to PG&E's overall RNS position, PG&E believes that its forecasts of meeting the second and third compliance period RPS targets as well as its incremental need year under either a 33% or 40% RPS would remain the same once these small GTSR volumes are incorporated. PG&E will update future RNS calculations to reflect GTSR program impacts after the advice letters implementing the program are approved.~~Programs.

In conformance with D.15-01-051[27] and as described in the Joint Procurement Implementation Advice Letter, PG&E will report annually on the amount of generation transferred between the RPS and GTSR Programs in a report to be filed on September 1 following the launch of each IOU's GTSR Program. PG&E will file its first Annual GTSR Tracking Report on September 1, 2017, to report generation transfers between the RPS and GTSR Programs. For purposes of this 2016 RPS Plan, PG&E updated the RNS calculations to reflect expected GTSR Program impacts on retail sales and RPS supply.

~~3.2.3~~3.2.3. RPS Market Trends and Lessons Learned

As ~~PG&E's~~its renewable portfolio has expanded to meet the RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the ~~three~~four key goals of: (1) reaching, and sustaining, the ~~33~~50% RPS target; (2) minimizing customer cost within an acceptable level of risk;~~ and~~ (3) ensuring it

[26] ~~Advice Letters 4637-E, 4638-E and 4639-E.~~

[27] *See* D.15-01-051, p. 50.

maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty~~. However,~~; and (4) aligning PG&E's RPS portfolio to its customers' needs. PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as solar PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

Another trend, driven by the growth of renewable resources in the California Independent System Operator ("CAISO") system, is the downward movement of mid-day market prices. Many renewable energy project types have little to no variable costs and therefore additions tend to move market clearing prices down the dispatch stack. This has led to a change in the energy values associated with RPS offers, with decreasing value of renewable projects that generate during mid-day hours.

The growth of renewable resources has also produced operational challenges, such as overgeneration situations and negative market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address overgeneration and negative pricing situations that are likely to increase in frequency in the future. These provisions have both operational and customer benefits. From an operational perspective, this flexibility allows PG&E to offer its RPS-eligible resources into the CAISO's economic dispatch, which can reduce the potential for overgeneration conditions and facilitate reliable operation of the electrical grid. In addition, economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 11.

~~3.3~~3.3. Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Compliance rules for the RPS Program were established in D.12-06-038. In addition, the Commission issued D.11-12-052, to define three statutory ~~PCCs~~portfolio content categories of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section ~~6~~4; in particular, uncertainty around bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

~~3.3.1~~3.3.1. Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need through [redacted] under a ~~33~~50% RPS requirement ~~and through [redacted] under a 40% RPS scenario~~, PG&E ~~plans~~is proposing not to hold an RPS solicitation ~~in 2015~~for the 2016 solicitation cycle. As discussed in the summary of key issues, PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future RFOs in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-~~-~~-term RPS requirements. Additionally, PG&E expects to ~~procure~~continue procurement of additional volumes of incremental RPS-eligible contracts in ~~2016~~2017 through mandated procurement programs, such as the ~~RAM,~~ ReMAT, BioRAM, and BioMAT Programs. PG&E will seek permission from the Commission should PG&E intend to procure any amounts other than amounts separately mandated by the Commission (*i.e.*, FIT and ~~RAM~~BioRAM) during the time period covered by the ~~2015 solicitation cycle~~2016 RPS Plan.

~~3.3.2~~3.3.2. Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. ~~PG&E's most recent Load Forecast, which is used in this RPS Plan, is an April 2015 updated version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan ("BPP") submitted in October 2014 in R.13-12-010. PG&E updates the bundled load forecasts annually to reflect any new events and to capture actual load changes. It is important to emphasize that PG&E's Alternative Scenario is a forecast that includes a number of assumptions regarding events which may or may not occur.~~

PG&E is currently projecting a decrease in retail sales in ~~2015~~2016 and a continued retail sales decrease through ~~2024~~2028, followed by modest growth thereafter. These changes are driven by the increasing impacts of Energy Efficiency~~,~~ (EE), customer-sited generation, and ~~Direct Access ("~~DA~~")~~ and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 6, 7~~,~~ and 8, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement; and (2) the need to account for its risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 6 and 7.

~~3.4~~3.4. Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs such as the ~~RAM,~~ ReMAT, BioRAM, and BioMAT Programs, PG&E does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost. Starting in the 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio. When this adder is finalized by the Commission, PG&E's Net Market Value ("NMV") methodology will be updated to use the values and methodologies of the final integration cost adder. PG&E's PAV and NMV methodologies were described in detail in PG&E's 2014 RPS Solicitation Protocol.[28]

~~3.5~~3.5. RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including solar PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the NMV valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of

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28 *See* PG&E, 2014 RPS Solicitation Protocol, pp. 24-28 (available at http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RPS2014/RPS_Solicitation_Protocol_01052015.pdf).

PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in procurement of different technology types.

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. In general, PG&E believes that less restrictive procurement structures provide the best opportunity to maximize value for its customers, allowing proper response to changing market conditions and more competition between resources, while geographic or technology-specific mandates add additional costs to RPS procurement. ~~PG&E's current quantitative and qualitative approach to resource diversity would remain the same under a 40% RPS scenario as the existing approach described above.~~

~~3.6~~3.6. Optimizing Cost, Value, and Risk for the Ratepayer

From 2003~~ to ~~-2012, PG&E's annual RPS-eligible procurement and generation costs from its existing contracts and utility-owned portfolio grew at a relatively modest pace. However, the costs of the RPS ~~program~~Program are becoming more apparent on customer bills and will increase as RPS projects come online in significant quantities. Over the period of ~~two years (~~2013 and 2014~~)~~, the renewable generation in PG&E's portfolio increased by approximately the same amount that it grew over the entire prior history of the RPS Program (2003-2012). During 2015, PG&E's renewable generation costs continued to increase. In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

PG&E is aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible~~, particularly when entering into incremental long-term commitments.~~. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet a physical compliance requirement; and (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline, and using the Bank to ~~help limit long-term over-procurement.~~mitigate risks associated load uncertainty, project failure, and generation variability. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section ~~13.3, as PG&E makes progress toward achieving the 33% RPS target, it expects that~~14.2, the cost impacts of mandated procurement programs that focus on particular technologies or project size may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process, in which all technologies can compete to offer the best value to customers at the lowest cost.

~~3.7~~3.7. Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond ~~2020~~2030 and to minimize customer cost within an acceptable level of risk. ~~PG&E's optimization strategy continues to evolve as its RPS compliance position through 2020 and beyond continues to improve.~~ Although PG&E remains mindful of meeting near-term compliance targets, it also seeks to refine strategies for maintaining compliance in a least-cost manner in the long-term (post-~~2020~~2030). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to manage a ~~33~~50% RPS operating portfolio after ~~2020~~2030. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 6 and 7.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement~~;~~ (if needed); (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E ~~will~~is proposing not to hold a ~~2015~~2016 RPS procurement solicitation, future incremental procurement to avoid the need to procure extremely large volumes in any single year remains a ~~central~~ component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes consideration of sales of surplus procurement that provide a value to customers. PG&E has developed a framework for surplus sales, which is described in Appendix J, and is requesting Commission approval of the proposed framework in this proceeding.

The third component of the optimization strategy is effective use of the Bank. Under the existing ~~33~~50% RPS target and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in [redacted]. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted] [redacted]. See Section 7 for additional information regarding the use and size of PG&E's Bank.

~~Under a 40% RPS by 2024 scenario, the components of PG&E's optimization strategy would remain the same. However, under the 40% RPS scenario and current market assumptions, PG&E would plan to maintain a minimum Bank size of at least~~ [redacted]~~. See Section 7 for additional information regarding the use and size of PG&E's Bank.~~

~~4~~4. Project Development Status Update

In Appendix B, PG&E provides an update on the development of RPS-eligible resources currently under contract but not yet delivering energy. The table in Appendix B updates key project development status indicators provided by counterparties and is current as of June ~~17, 2015~~1, 2016.[29] These key project development status indicators help PG&E to determine if a project will meet its contractual milestones and identify impacts on PG&E's renewable procurement position and procurement decisions. Appendix B includes in-development GTSR dedicated contracts that—though RPS eligible—are not counted towards PG&E's RPS position, as explained in Section 3.2.2 and Appendix G.

Within PG&E's active portfolio,[30] there are ~~107~~117 RPS-eligible projects that were executed after 2002. ~~Seventy-six~~Eighty-three of these contracts have achieved

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29 Appendix B includes PPAs procured through the GTSR Program, RAM, and PV Programs, but does not include small renewable FIT PPAs. PG&E currently has ~~72~~ 69 executed Assembly Bill ("AB") 1969 PPAs in its portfolio and ~~29~~31 ReMAT PPAs, totaling ~~104~~101.1125 MW of capacity. These small renewable FIT projects are in various stages of development, with ~~60~~68 already delivering to PG&E under an AB 1969 PPA and ~~11~~14 delivering to PG&E under a ReMAT PPA. Information on these programs is available at http://www.pge.com/feedintariffs/.

30 PG&E's active portfolio includes RPS-eligible projects that were executed (but not terminated or expired) and ~~**CPUC**~~ have been approved ~~**as of June 17, 2015**~~by the

full commercial operation and started the delivery term under their PPAs. Thirty-~~one~~ four contracts have not started the delivery term under their PPAs. Of the ~~31~~34 contracts that have not started the delivery term under their PPAs with PG&E: ~~18~~26 have not yet started construction; ~~five~~three have started construction, but are not yet online; ~~and eight~~four are delivering energy, but have not yet started the delivery term under their PPAs~~. Based on historic experience,~~, and one contract is delivering energy under its current RPS contract expiring in 2016 and will be starting the delivery term under a new RPS contract thereafter.

In addition, 8 of the 117 total RPS-eligible projects ~~that~~ are designated for the GTSR Program. All eight projects have ~~commenced~~not currently started construction ~~are generally more viable than projects in the pre-construction phase, although PG&E expects most of the pre-construction~~and are expected to come online by April 2018. How these GTSR-dedicated projects ~~currently~~ are accounted for in ~~its portfolio to achieve commercial operation under their PPA~~PG&E's RPS position modeling is discussed in Section 3.2.2 and Appendix G.

~~5~~5. Potential Compliance Delays

This section addresses: (1) obstacles for renewable project developers; and (2) how PG&E mitigates these risks of compliance delay in its modeling and planning.[31]

Commission, not including amended post-2002 Qualifying Facility ("QF") contracts, contracts for the sale of bundled renewable energy and green attributes by PG&E to third parties, Utility-Owned Generation ("UOG") projects, or FIT- projects.

31 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

5.1. Potential Causes of Compliance Delays as a Result of Obstacles to Renewable Project Development

Through the considerable experience it has gained over the past decade of RPS procurement, PG&E is familiar with the obstacles confronting renewable energy developers. ~~These~~Significant obstacles include securing project financing, siting and permitting projects, expanding transmission capacity, and interconnecting projects to the grid. At both the federal and state levels, new programs and measures continue to be implemented to address these issues. ~~However, even with these efforts, challenges remain that could ultimately impact PG&E's ability to meet California's RPS goals. Moreover, operational issues, such as curtailment, may impact PG&E's RPS compliance. This section describes the most significant RPS compliance risks and some of the steps PG&E is taking to mitigate them.~~~~[32]~~

~~5.1~~5.1.1. Project Financing

The financing environment for solar PV and wind projects continues to be healthy, with access to low-cost capital, a growing number of investors, and a variety of ownership structures for project developers. ~~However, for renewable technologies that are less proven, less viable, or reflect a higher risk profile, the financing environment is more constrained~~Wind and solar deals saw an increase in project finance volume in 2015, with ~~higher costs of capital and fewer participants willing to lend or invest.~~further volume growth expected in 2016 as well.[33]

~~32 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.~~

33 http://www.renewableenergyworld.com/articles/2016/02/renewable-energy-finance-outlook-2016-the-year-of-the-green-dollar.html.

Federal and state incentives such as the PTC and ITC continue to fuel renewable growth in California. In late 2015, ~~the Internal Revenue Service~~Congress extended the ~~applicable dates~~ ITC for solar energy, the PTC for wind and other renewable resources, and bonus depreciation.[34] For many developers, this event added significant value to their companies. In addition, the ~~"beginning~~lengthy extensions of the tax credits have provided certainty and caused a developer shift towards raising capital and expansion.

The table below shows the value of the ITC for each renewable technology by year. For solar technologies and wind, the expiration date is based on "commencement of construction~~" guidance for PTC-eligible facilities to January 1, 2015, and the "~~." For all other renewable technologies, the expiration date is based on when the system is placed in service~~" date to January 1, 2017.[35] This allows~~.[36]

[34] On December 18, 2015, President Barack Obama signed into law the Consolidated Appropriations Act, 2016 (Act). *See* I.R.S. Notice 2013-29, 2013-20 I.R.B. 1085, as clarified by I.R.S. Notice 2013-60, 2013-42 I.R.B. 431, as clarified and modified by I.R.S. Notice 2014-46, 2014-35 I.R.B. 520, and as updated by I.R.S. Notice 2015-25, 2015-13 I.R.B.

~~[35] Notice 2015-2025 allows a taxpayer to claim a PTC under Section 45 of the Internal Revenue Code ("IRC"), or a 30% ITC under Section 48 (ITC) in lieu of the PTC, for eligible facilities such as wind, geothermal, biomass, marine, landfill gas, and hydro, if the facility began construction before January 1, 2015 or was placed in service by January 1, 2017.~~

[36] Solar projects will qualify for the 30 percent ITC if construction begins on or before December 31, 2019, even if the projects are not placed in service until after that date. However, the project must be placed in service before January 1, 2024. Projects placed in service on or after that date would qualify for a 10 percent credit.

Renewable Energy Investment Tax Credit[37]								
Technology	**12/31/16**	**12/31/17**	**12/31/18**	**12/31/19**	**12/31/20**	**12/31/21**	**12/31/22**	**Future Years**
PV, Solar Water Heating, Solar Space Heating/Cooling, Solar Process Heat	30%	30%	30%	30%	26%	22%	10%	10%
Hybrid Solar Lighting, Fuel Cells, Small Wind	30%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Heat Pumps, Microturbines, Combine Heat and Power Systems	10%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Geothermal Electric	10%	10%	10%	10%	10%	10%	10%	10%
Large Wind	30%	24%	18%	12%	N/A	N/A	N/A	N/A

For wind facilities, the PTC ~~or ITC tax benefits for non-solar facilities to continue well beyond 2014. Solar energy facilities continue to be eligible~~was extended for ~~a 30% ITC if they are placed in service by December 31, 2016.[38] The five-year and seven-year Modified Accelerated Cost Recovery System ("MACRS") allows~~two years and also structured to phase out. The table below shows the value of the PTC for ~~accelerated~~ each renewable resource.

[37] Per Section 48 of the Internal Revenue Code. The energy ITC is realized in the year that the project is placed in service.

~~[38] Section 48 of the IRC allows for a tax credit equal to 30% of project's qualifying costs for certain types of commercial energy projects, including solar, geothermal, fuel cells, and small wind projects, and a 10% tax credit for geothermal, micro turbines and combined heat and power. The tax credit is realized in the year that the project is placed in service.~~

Renewable Energy Production Tax Credit[39]		
Resource	**Tax Credit Amount**	**Period of Credit**
Wind[40]	2.3 cents per kilowatt-hour (kWh) (inflation adjusted) for facility starting construction through December 31, 2019, with a phase-down beginning for wind projects commencing construction after December 31, 2016: • facilities commencing construction in 2017, the PTC amount is reduced by 20%; • facilities commencing construction in 2018, the PTC amount is reduced by 40%; • facilities commencing construction in 2019, the PTC amount is reduced by 60%	10 years
Geothermal Energy Resources, Closed-Loop Biomass	2.3 cents per kWh (inflation adjusted) for facility starting construction through December 31, 2016	10 years
Open-loop biomass, Landfill gas, Municipal solid waste, Qualified hydroelectric Marine & hydrokinetic energy resources	1.2 cents per kWh (inflation adjusted) for facility starting construction through December 31, 2016	10 years

39 Per Section §45 of the Internal Revenue Code.

40 Wind facilities may also claim the 30 percent energy ITC in lieu of the PTC if the facilities begin construction on or before December 31, 2016.

Congress also extended the bonus depreciation through 2019, as follows:

Tax Depreciation	
For Qualified Property Placed in Service:	**Tax Depreciation Allowance**
On or before December 31, 2017	50% Bonus Depreciation, then Modified Accelerated Cost Recovery System (MACRS)[41]
In 2018	40% Bonus Depreciation, then MACRS
In 2019	30% Bonus Depreciation, then MACRS
Beyond 2019	5 and 7 MACRS

The tax incentives and the tax depreciation deductions ~~to renewable tangible property.~~[42] ~~These tax incentives and the MACRS depreciation deductions~~ enable developers and businesses to reduce their tax liability and accelerate the rate of return on renewable investments. They also provide a workable framework for ~~projects to negotiate~~negotiating financing~~.~~ arrangements. As a result, the tax incentives ~~have spurred~~encourage significant investment in renewable energy and generally amount to between 35 and 60 cents per dollar ~~("¢/$")~~ of capital cost.

Tax equity remains a core financing tool for renewable developments~~,~~ and ownership structures such as the partnership flip, Master Limited Partnerships, and Yield Cos ~~are also being~~continue to be utilized ~~as~~by project sponsors ~~market and investors competitively shop for solar and wind investments~~. These structures allow developers who cannot use tax benefits efficiently to barter the benefits to large corporations or investors in exchange for cash infusions for their projects. ~~At this time, tax incentive structures after 2016 are unknown. The PTC and 30% ITC incentives end~~

41 MACRS provides for a five-year tax cost recovery period for renewable solar, wind, geothermal, fuel cells and combined heat and power tangible property. Certain biomass property is eligible for a seven-year tax cost recovery period under MACRS.

~~42 MACRS provides for a five-year tax cost recovery period for renewable solar, wind, geothermal, fuel cells and combined heat and power tangible property. Certain biomass property is eligible for a seven-year tax cost recovery period under MACRS.~~

~~in 2016. Unless the tax code is modified or extended, the renewable energy ITC will drop to 10% after December 31, 2016. However, there are efforts underway to extend or modify the PTC and ITC.[43] Despite the uncertainty surrounding renewable energy project tax incentives, PG&E believes there are indications that healthy trends for renewable project financing will continue.~~

PG&E believes the healthy trends for renewable project financing will continue well into the future.

~~5.2~~5.1.2. Siting and Permitting

PG&E works with various stakeholder groups toward finding solutions for environmental siting and permitting issues faced by renewable energy development. For example, PG&E works collaboratively with environmental groups, renewable energy developers and other stakeholders to encourage sound policies through a Renewable Energy Working Group, an informal and diverse group working to protect ecosystems, landscapes and species, while supporting the timely development of energy resources in the California desert and other suitable locations. Long-term and comprehensive planning and permitting processes can help better inform and facilitate renewable development.

PG&E is hopeful that these and other efforts will establish clear requirements that developers and other interested parties can satisfy in advance of the submission of

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~~43 H.R. 2412 would extend the renewable energy ITC for a period of five years for eligible renewable solar, small wind energy, fuel cell, micro turbine, thermal energy and combined heat and power system properties that begin construction before January 1, 2022.~~

~~In addition, in its proposed budget for fiscal year 2016, the Obama administration proposes to modify and permanently extend the renewable PTC and ITC. For facilities that begin construction in 2016 or later, the proposal would make the PTC permanent and refundable. Solar facilities that qualify for the ITC would be eligible to claim the PTC. The proposal would also permanently extend the ITC at the 30 percent credit level, which is currently scheduled to expire for properties placed in service after December 31, 2016, and it would make permanent the election to claim the ITC in lieu of the PTC for qualified facilities eligible for the PTC.~~

offers to PG&E's future solicitations, and will, as a result, help decrease the time it takes parties to site and permit projects while ensuring environmental integrity.

Permitting challenges for projects are improving as a result of these and other efforts to streamline and adjust the permitting process for renewable energy projects. While these improvement efforts are ongoing, permitting and siting hurdles remain for renewables projects. Common issues may include challenges related to farmland designation and Williamson Act contracts, tribal and cultural resources areas, protected species, and county-imposed moratoriums. These hurdles may impact development schedules for projects.

~~5.3~~5.1.3. Transmission and Interconnection

Achieving timely interconnection is an important part of the project development process. Delays in achieving interconnection can occur for various reasons, including the delay of substation construction, permitting issues, telecommunications delays, or overly aggressive timeline assumptions~~.~~ on the part of interconnection customers. While delays in interconnection can lead to delays in project development, such delays to date have not had a major impact on PG&E's ability to meet its RPS procurement targets.

Over the past few years, the CAISO and the IOUs have seen significant increases in the number of requests for grid interconnection. As the number of proposed RPS-eligible projects continues to increase in California, planning for how these projects would be connecting into the California grid has become increasingly challenging. ~~The growth in these requests has, in turn, extended estimated project development timelines, which creates a significant barrier to financing projects endeavoring to come online within tight contractual milestone dates. Similarly, the growth in interconnection requests has made it difficult to estimate reliable interconnection study results and to identify necessary transmission build-outs.~~Additionally, projects often withdraw from the interconnection process for a variety of reasons, including a lack of commercial viability, and these withdrawals significantly impact other projects that remain active and change the system planning assumptions. This in turn makes identifying upgrades and associated costs a dynamic process that can be challenging for both IOUs and interconnection customers to manage, increasing the need for effective queue management.

Accordingly, PG&E has initiated a number of internal efforts and collaborated on external initiatives to address these challenges at both the transmission and distribution levels. Recent notable changes in the distribution-level interconnection process included: (1) amending the Wholesale Distribution Tariff in October 2014 to address modifications similar to those made to the CAISO's Tariff; and (2) amending Rule 21 in January 2015 to capture the technological advances offered by smart inverters. Additional amendments to the Wholesale Distribution Tariff are underway currently to address recent proposals for a Distributed Group Study Process and project naming conventions, and to clarify financial security requirements and procedures.

Additionally, over the past few years, PG&E has worked with the CAISO and industry stakeholders in ongoing stakeholder initiatives enhancing the transmission-level interconnection processes. Most significant among the changes has been the Generator Interconnection and Deliverability Allocation Procedures~~,~~ ("GIDAP"), which has streamlined the process for identifying customer-funded transmission additions and upgrades under a single comprehensive process. This initiative also provides incentives for renewable energy developers to interconnect to the CAISO grid at the most cost~~-~~-effective locations. PG&E has also actively contributed to the CAISO's Interconnection Process Enhancements stakeholder initiative that seeks to continuously review potential enhancements to the generator interconnection procedures.

More recently, PG&E is supporting the Renewable Energy Transmission Initiative 2.0 ("RETI 2.0") that was initiated jointly by the California Energy Commission, CPUC, CAISO, and the California Natural Resources Agency to facilitate electric transmission coordination and planning towards achieving California's 2030 goals.

While RETI 2.0 is not a regulatory proceeding, PG&E supports RETI 2.0 as an initiative that can help inform future transmission planning proceedings.[44]

PG&E is supportive of the CAISO's and Commission's recent efforts to examine the potential impact of energy only ("EO") resources on transmission planning. The CAISO's 2015-2016 Transmission Plan included an informational "Special Study" that included energy only resources, and the CAISO's upcoming 2016-2017 Transmission Planning Process ("TPP") will help further that analysis.[45] In addition, the Commission has updated the RPS Calculator to include 50% RPS scenarios that consider the potential procurement of energy only resources.[46] PG&E is actively supporting these initiatives.

Partially deliverable and energy only contracts are currently a viable option for some renewable resources, and PG&E supports the ongoing study of the relative costs and benefits of energy only versus full deliverability. PG&E believes the current Least-Cost Best-Fit ("LCBF") methodology adequately captures the benefits and costs of the tradeoff between EO and full deliverability via the value of Resource Adequacy and the transmission cost adder. PG&E believes the current planning processes, including the Commission's IRP/Long-Term Procurement Plan ("LTPP"), and CAISO's TPP and GIDAP, are the proper venues to re-examine the transmission and sub-transmission needs for EO projects.

5.2. Consideration of Compliance Delay Risks in PG&E's RPS Strategy

Despite the ongoing efforts to address the potential delays noted above, challenges remain that could ultimately impact PG&E's RPS position. Moreover, operational issues, such as curtailment, may impact PG&E's RPS compliance. ~~Finally,~~

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44 *See* RETI 2.0 Website at http://www.energy.ca.gov/reti/.

45 *See* CAISO Website at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.

46 *See* CPUC Website at http://www.cpuc.ca.gov/RPS_Calculator/.

~~at the intersection of transmission-level and distribution-level interconnections, is the Distributed Generation Deliverability ("DGD") process. In 2013, PG&E collaborated extensively with the CAISO to implement the first annual cycle, and the second and third cycles were successfully completed in 2014 and 2015, respectively. Under the DGD Program, the CAISO conducts an annual study to identify MW amounts of available deliverability at transmission nodes on the CAISO-controlled grid. Based on the deliverability assessment results, distributed generation facilities that are located or seeking interconnection at nodes with identified available deliverability may apply to the appropriate Participating Transmission Owner ("PTO") to receive an assignment of deliverability for Resource Adequacy ("RA") counting purposes.~~

This section describes briefly some of the steps PG&E is taking to mitigate these risks.

~~5.4~~5.2.1. Curtailment of RPS Generating Resources

As discussed in more detail in Section 11, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may ~~present an~~reduce the RPS energy available for compliance ~~challenge~~. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 6.2.

~~5.5~~5.2.2. Risk-Adjusted Analysis

PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. As described further in Section 6, deliveries from projects experiencing considerable development challenges associated with project financing, permitting, transmission and interconnection, among others, are excluded from PG&E's net short calculation.

PG&E's experience with prior solicitations is that developers often experience difficulties managing some of the development issues described above. As described in Section 8, PG&E's ~~current~~ expected RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio, which are captured in PG&E's deterministic model.[47] These deterministic results ~~are time-sensitive and~~ do not account for all of the risks and uncertainties that can cause substantial swings in PG&E's portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the ~~33~~50% RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

~~6~~6. Risk Assessment

Dynamic risks, such as the factors discussed in Section 5 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. To account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales ~~variability~~uncertainty and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The

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47 As described in Section 3.2.1, PG&E currently assumes a project development success rate of 100% in its deterministic model.

stochastic model[48] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as ~~Voluntary Margin of Procurement or~~ VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.[49]

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 6.1 identifies the three risks accounted for in PG&E's deterministic model. Section 6.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 6.3 describes how the risks described in the first two sections are incorporated into both models, including details about how each model operates and the additional boundaries each sets on the risks. Section 6.4 notes how the two models help guide PG&E's optimization strategy and procurement need. Section 7 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices C.~~2a~~1 and C.~~2b~~2. Section 8 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

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48 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

49 PG&E has also developed a framework to assess whether to hold or sell excess RPS volumes, included in Appendix J.

~~6.1~~6.1. Risks Accounted for in Deterministic Model

PG&E's deterministic approach models three key risks:

1) Standard Generation Variability: the assumed level of deliveries for categories of online RPS projects.

2) Project Failure: the determination of whether or not the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.

3) Project Delay: the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

TABLE 6-1
~~**PACIFIC GAS AND ELECTRIC COMPANY**~~
DETERMINISTIC MODEL RISKS

RISK	METHODOLOGY	APPLIES TO
Standard Generation Variability	• For non-QF projects executed post-2002, 100% of contracted volumes • For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries • Hydro QFs, UOG and ~~IDWA~~Irrigation District and Water Agency ("ID&WA") generation projections are updated to reflect the most recent hydro forecast.	Online Projects
Project Failure	• In Development projects with high likelihood of failure are labeled "OFF" (0% deliveries assumption) • All other In Development projects are "ON" (assume 100% of contracted delivery)	In Development Projects
Project Delay	• Professional judgment/Communication with counterparties	Under Construction Projects/ Under Development Projects/ Approved Mandated Programs

~~6.1.1~~6.1.1. Standard Generation Variability

With respect to its operating projects, PG&E's forecast is divided into three categories: non-~~Qualifying Facilities ("~~QF~~")~~;; non-hydro QFs; and hydro QF projects. The forecast for non-~~-~~-QF projects is based on contracted volumes. The forecast for non-hydro QFs is typically based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, ~~calendar~~normalized for average water year ~~deliveries~~conditions, and ~~regularly updated with~~then adjusted to reflect PG&E's latest internal hydro ~~updates~~outlook. The UOG and ~~Irrigation District and Water Agency ("~~IDWA~~")~~ forecast ~~is~~are based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix G.

~~6.1.2~~6.1.2. Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0% deliveries) and ON (represented with 100% deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

1. **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers

may consider the following factors when deciding whether to categorize a project as "Closely Watched":

- Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc~~.).~~.);
- Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as~~-~~ informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data~~).~~);
- Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization~~.~~;
- Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability~~.~~;
- Whether a PPA amendment has been executed but has not yet received regulatory approval~~.~~; and
- Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as "Closely Watched."[50] PG&E does not currently have any in-development projects categorized as "OFF" in its deterministic model.

2. **ON** – Projects in all other categories are assumed to deliver~~-~~ 100% of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of "ON"~~-~~ projects. Based on empirical experience and industry benchmarking, PG&E

50 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

estimates that this population is highly likely to deliver. The second category of “ON”~~-~~ projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of “ON” projects represents executed and future contracts from ~~CPUC~~Commission-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes ~~with replacement projects~~ within a reasonable timeline.

~~6.1.3~~6.1.3. Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

~~6.2~~6.2. Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E’s RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E’s portfolio. PG&E’s stochastic model assesses the impact of both demand~~-~~- and-supply-side variables on PG&E’s RPS position from the following four categories:

1) Retail Sales ~~**Variability**~~Uncertainty: This demand-side variable is one of the largest drivers of PG&E’s RPS position~~.~~;
2) Project Failure Variability: Considers additional project failure potential beyond the “on-off” approach in the deterministic model~~.~~;

3) Curtailment: Considers buyer-ordered (economic), CAISO-ordered or Participating Transmission Owner ("PTO~~-~~")-ordered curtailment~~.~~; and

4) RPS Generation Variability: Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year-to-year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 6-2
~~PACIFIC GAS AND ELECTRIC COMPANY~~
CATEGORIZATION OF IMPACTS ON RPS POSITION

~~Higher Impact on RPS Position~~

Impact	Categorization
1. Retail Sales ~~Variability~~Uncertainty: Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** *(If an outcome occurs, the effect persists through more than one year).*
2. Curtailment: ~~2.~~ Impact increases with higher penetration of renewables and will be persistent.**~~RPS Generation Variability:~~** ~~Variability in yearly generation is largely an annual phenomenon that has little persistence across time.~~	**Variable and ~~short-term~~** ~~*(If an outcome occurs, the effect may only occur for the individual year.)*~~**persistent**
3. RPS Generation Variability: ~~3.1.~~Variability in yearly generation is largely an annual phenomenon that has little persistence across time.**~~Curtailment:~~** ~~Impact increases with higher penetration of renewables and will be persistent.~~	**Variable and ~~persistent~~short-term** *(If an outcome occurs, the effect may only occur for the individual year.)*
4. Project Failure Variability: Lost volume from project failure persists through more than one year.	**Variable and persistent**

Lower Impact on RPS Positi

~~Lower Impact on RPS Position~~

~~6.2.1~~6.2.1. Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, ~~EE~~energy efficiency, levels of DA and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on ~~EE~~energy efficiency, electric vehicles, and distributed generation. However, the variability in load loss due to DA and CCA is not modeled in this same way. As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting substantial increases in DA. Load loss due to CCA departure is modeled as ~~an expected value~~[redacted] based on ~~an increased~~a forecast of CCA departure. Because forecast errors tend to carry forward into future years, the cumulative impact of load forecast ~~variability~~uncertainty grows with time. Appendix F.1 lists the resulting simulated retail sales and summary statistics for the period ~~2015~~2016-2030. ~~Appendices~~Appendix F.~~5a and F.5b show~~5 shows the resulting simulated RPS target when accounting for the retail sales ~~variability~~uncertainty for the period ~~2015-~~2016-2030~~ in the 33% and 40% RPS, respectively~~.

~~6.2.2~~6.2.2. RPS Generation Variability

Based on analysis of historical hydro generation data from [redacted]1985-2012, wind generation data from [redacted]1985-2011, and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is ~~essentially~~ uncorrelated among technologies. ~~Appendices~~Appendix F.~~3a and F.3b list~~3 lists the resulting simulated generation and summary statistics for the period ~~2015~~2016-2030 ~~in the 33% and 40% RPS, respectively~~.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes, ~~Appendices F.4a and F.4b, combine~~Appendix F.4 combines the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, and shows how these variables interact ~~in the 33% and 40% RPS, respectively.~~.

~~6.2.3~~6.2.3. Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). [redacted][51] ~~These modeling assumptions will not necessarily align with~~Curtailment ramps from a historical level of

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[51] [redacted]

[redacted].[52] ~~These modeling assumptions will not necessarily reflect~~ the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information regarding curtailment.

~~6.2.4~~6.2.4. Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. ~~Projects that are re-contracted, in contrast, are modeled at a~~ [redacted] ~~success rate.~~

[52] [redacted]

~~Appendices~~Appendix F.~~2a and F.2b list~~2 lists PG&E's simulated failure rate and summary statistics for the period ~~2015~~2016-2030~~ in the 33% and 40% RPS, respectively~~.

~~6.2.5~~6.2.5. Comparison of Model Assumptions

Table 6-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, RPS generation, and curtailment. Section 7 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 6-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty[53]	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years (Appendix C.1); Uses most recent PG&E bundled retail sales forecast for all years (Appendix C.2).	Distribution based on most recent (~~2015~~2016) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] ~~XXXXXXXXXXXXX~~XXXXXXXXXXX to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. ~~Re-contracted projects are assumed to have a~~ [redacted] ~~success rate.~~
3) RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes~~ ~~. For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries. Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4) Curtailment~~[54]~~	None	~~33% RPS Target:~~ [redacted] ~~of RPS requirement~~ ~~40% RPS Scenario:~~ [redacted] ~~of RPS requirement through 2021,~~Curtailment is modeled as increasing ~~to~~ between the following data points:

53 These modeling assumptions will not necessarily align with the future actual sales, project failure rates, RPS generation, and curtailment hours, but are helpful in terms of considering the impact of uncertainty on long-term RPS planning and compliance.

~~54 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance.~~

		[redacted] in 2015 [redacted] in 2020 [redacted] in 2024~~ and beyond.~~ [redacted] in 2030

~~6.3~~6.3. How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position~~ and procurement need.~~. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

~~6.4~~6.4. How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives~~,~~; (b) inputs~~,~~; and (c) constraints of the model~~.~~:

   (a~~.~~) The objective is to~~ ~~ minimize procurement cost.

   (b~~.~~) The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes[55]) in each year of the [redacted] timeframe. The

55 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, ~~the stochastic model can also re-contract volumes to meet procurement need. Such re-contracting amounts are illustrative only and not prescriptive.~~this modeling approach assumes re-contracting will be considered in the future side-by-side with procurement of other new resources.

potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] ~~GWh, which is in addition to volumes available for re-contracting.~~[56] [redacted] annually.

(c~~.~~) The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted], less than [redacted], less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.

3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.

4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not ~~currently consider speculating on~~allow for price ~~volatility~~arbitrage through sales of PG&E's Bank in the near-term and additional incremental procurement in the long~~-~~-term. Nor does the model consider the opposite strategy of advance procurement of RPS~~-~~-eligible products in ~~2015~~2016 for

[56] ~~PG&E limited modeling to a maximum addition of~~ [redacted] ~~GWh per year in order to avoid modeling outcomes that required "lumpy" procurement patterns. Large swings in annual procurement targets could lead to boom/bust development cycles and could expose PG&E's customers to additional price volatility risk.~~

purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this ~~Plan. However, PG&E will consider selling surplus non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable.~~2016 RPS Plan.

~~6.5~~6.5. Incorporation of the Above Risks in the Two~~-~~ Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the ~~33% and 40%~~ 50% RPS are shown in Row La of PG&E's Alternate RNS in ~~Appendices~~Appendix C.~~2a and C.2b~~2.

~~The stochastic model does not provide guidance on potential sales of excess banked procurement at this time. However, as PG&E encounters economic opportunities to sell volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for~~ [redacted] ~~above the~~ [redacted] ~~threshold.~~

The results of both the deterministic and stochastic models are discussed further in Section 7 and minimum margin of procurement is addressed in Section 8.

~~7~~7. Quantitative Information

As discussed in Section 6, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix C. ~~Appendices C.1a and C.1b~~Appendix C.1 presents the RNS in the form required by the *Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while ~~Appendices~~Appendix C.~~2a and C.2b are~~2 is a modified version of ~~Appendices~~Appendix C.~~1a and C.1b~~1 to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its ~~bank~~Bank size and PG&E's analysis of the minimum bank needed. However, in approving the 2015 RPS Plan, the Commission expressly rejected any specific bank size proposal~~ and instead indicated that proposals regarding bank size should be considered in SB 350's implementation.~~.[57]

~~7.1~~7.1. Deterministic Model Results

Results from the deterministic model under ~~the 33% ~~a 50% RPS target are shown as the physical net short in Row Ga of Appendices C.~~1a~~1 and~~ ~~ C.~~2a, while the results from the deterministic model under the 40% RPS scenario are shown as the physical net short in Row Ga of Appendices~~2. Appendix C.~~1b and C.2b. Appendices C.1a and C.1b provide~~1 provides a physical net short calculation using PG&E's April 2016 Bundled Retail Sales Forecast for years ~~2015-2019~~2016-2020 and the LTPP sales forecast for ~~2020-2035,~~2021-2036,[58] while ~~Appendices~~Appendix C.~~2a and C.2b rely~~2 relies exclusively on PG&E's internal Bundled Retail Sales Forecast. Following the methodology described in Section 6.1, PG&E currently estimates a long-term volumetric success rate of ~~approximately 99~~100% for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of

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[57] D.15-12-025, pp. 106-107.

[58] Sales forecast used is from the most recently approved bundled sales forecast filed in PG&E's 2014 Conformed Bundled Procurement Plan in AL 4750-E and approved June 15, 2016.

~~Appendices~~Appendix C.~~2a and C.2b~~2. This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 5, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of ~~Appendices~~Appendix C.~~2a and C.2b~~2 depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.

~~7.1.1~~7.1.1. ~~33~~50% RPS Target Results

Under the current ~~33~~50% RPS target, PG&E is well-positioned to meet its second (2014-2016~~) and~~), third (2017-2020), and fourth (2021-2024) compliance period RPS requirements. As shown in Row Gb of Appendix C.~~1b~~1, the deterministic model shows a forecasted second compliance period RPS Position of ~~30.3% and~~29.9%, a third compliance period RPS position of ~~[redacted].~~ [redacted], a fourth compliance period RPS position of 32.3%, a fifth compliance period RPS position of 30.2%, and a sixth compliance period RPS position of 29.2%. Row Ga of Appendix C.~~2a~~2 also shows a physical net short of ~~approximately 500~~433 GWh beginning in ~~2022.~~

~~7.1.2 40% RPS Scenario Results~~

~~Under a 40% RPS scenario, PG&E is forecasted to meet its second (2014-2016) and third (2017-2020) compliance period RPS requirements. As shown in Row Gb of Appendix C.2b, PG&E has a forecasted second compliance period RPS Position of 30.3% and a third compliance period RPS position of [redacted]. Row Ga of Appendix C.2b shows a physical net short of approximately 3,000 GWh beginning in 2022~~2026.

~~7.2~~7.2. Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for ~~both the current 33% RPS target and a 40% RPS scenario. All assumptions and caveats stated in the discussion of the 33% RPS target results apply to the 40% RPS scenario results, unless otherwise stated. However, note that the~~

~~40% RPS scenario results apply to this particular RPS scenario only, and PG&E's optimization strategy may differ under other scenarios that have a different RPS target or timeline.~~the 50% RPS target. Because PG&E uses its stochastic model to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix C.~~2a~~2 for the ~~current 33~~50% RPS target~~ and~~. Appendix C.~~2b for the 40% RPS scenario. Appendices C.1a and C.1b provide~~1 provides an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In ~~Appendices~~Appendix C.~~2a and C.2b~~2, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

~~7.2.1~~7.2.1. Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target ~~– 33% RPS Target~~

To evaluate possible procurement strategies, PG&E selected ~~a cumulative~~ [redacted]the following non-compliance risk ~~target of~~ [redacted]~~, which PG&E views as the maximum reasonable level of non-~~targets for each future compliance ~~risk.~~ period: [redacted]

[redacted]

Figure 7-1 shows the model's forecasted procurement need and resulting Bank usage under the ~~current 33~~50% RPS by 2030 target. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in [redacted], the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section~~-~~ 6. Appendix C.~~2a~~2 provides the detailed results. Annual forecasted Bank usage is shown in Row ~~Ia~~La of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as [redacted]. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for [redacted] is approximately [redacted] GWh, which increases to approximately [redacted] GWh by ~~2030~~[redacted]. The [redacted] SONS is [redacted] than the physical net short in Row Ga for [redacted], as the SONS [redacted]. Should PG&E engage in RPS sales, its position will be updated in subsequent RPS Plans to reflect an earlier procurement need year.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re~~-~~-assessed as part of future RPS Plans.

~~7.2.2~~7.2.2. Bank Size Forecasts and Results~~ – 33% RPS Target~~

Figure 7-2 shows PG&E's current and forecasted cumulative Bank from the first~~-~~ compliance period~~-~~ through ~~2030~~2033. PG&E's total Bank size as of the end of the first compliance period~~-~~ is approximately 900 GWh~~, shown as existing Bank in Figure 7-2~~.. The stochastic model's results currently project PG&E's Bank size to [redacted] GWh by [redacted] (as shown in Figure 7-2, as well as in Appendix C.~~2a~~2, Row J). [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement.

In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases. [redacted]

~~7.2.3~~7.2.3. Minimum Bank Size ~~– 33% RPS Target~~

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at- least [redacted] is the minimum Bank necessary to maintain a cumulative non--compliance risk of no greater than [redacted].[59] The difference between delivery and target can be thought of as the potential "need" (if negative) or "surplus" (if positive) that PG&E has in any one year.

Figure 7-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted]~~. This time period was selected as it best represents a "steady state" period when the Bank approaches a minimum level and moderate incremental procurement is required to maintain compliance. Note that given the uncertainty around the inputs in the stochastic model, without a Bank to accommodate such uncertainty, the amount of RPS generation is almost as likely to miss the RPS target as exceed it. One standard deviation over~~ [redacted] ~~is approximately~~ [redacted] ~~GWh, as indicated on Figure 7-3. That is, given this particular procurement scenario, about 68% of the simulations have a difference that is up to plus or minus approximately~~

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59 [redacted]

[redacted] ~~GWh.~~[redacted]

~~However, this does not suggest that a Bank of~~ [redacted] ~~GWh would be adequate to cover potential shortfalls over this~~ [redacted]~~-year period. It would result in an unacceptable non-compliance risk over~~ [redacted] ~~of approximately~~ [redacted]~~. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level.~~ Based on current model assumptions and inputs, Figure 7-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level. As discussed above in Section 7.2.1, PG&E has selected cumulative non-compliance risk targets of [redacted].

[redacted]

[redacted]

[redacted]

[redacted]

As stated in Section 7.2.2, the stochastic model's results show PG&E's forecasted [redacted], PG&E's strategy is to procure steady, incremental volumes in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs and maintain minimum Bank levels. [redacted]

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 7-3 illustrates.

~~7.2.4 Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target – 40% RPS Scenario~~

~~Figure 7-4 shows the model's forecasted procurement need and recommended Bank usage in the 40% RPS scenario. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in~~ [redacted]~~, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 6. Appendix C.2b provides the detailed results. Annual forecasted Bank usage can be seen in Row Ia of this Appendix. The first year of procurement need is currently forecasted as~~ [redacted]~~. This compliance period need represents PG&E's SONS, which is detailed in Row La. The SONS for~~ [redacted] ~~is approximately~~ [redacted] ~~GWh, which increases to approximately~~ [redacted] ~~GWh by~~ [redacted]~~. The~~ [redacted] ~~SONS is~~ [redacted] ~~than the physical net short shown in Row Ga for~~ [redacted]~~.~~

[redacted]

[redacted]

[redacted]

~~7.2.5 Bank Size Forecasts and Results – 40% RPS Scenario~~

~~Figure 7-5 shows PG&E's current and forecasted cumulative Bank from Compliance Period 1 through 2030 under a 40% RPS scenario. PG&E's total Bank size as of the end of Compliance Period 1 is approximately 900, shown as existing Bank in Figure 7-5. The stochastic model's results currently project PG&E's~~ [redacted] ~~(as shown in Figure 7-5, as well as in Appendix C.2b, Row J).~~

[redacted]

[redacted]

[redacted]

~~7.2.6 Minimum Bank Size – 40% RPS Scenario~~

~~Using a similar approach as described in Section 7.2.3, under a 40% by 2024 scenario, a minimum Bank size of at least~~ [redacted] ~~GWh is necessary to maintain a cumulative non-compliance risk of no greater than~~ [redacted]~~. The minimum Bank size in this scenario is greater than the Bank required for the 33% RPS target, as more volumes are required to meet the higher RPS, but also~~ [redacted]~~.~~

[redacted]

[redacted]

~~The stochastic model's procurement strategy results show PG&E's forecasted~~ [redacted]~~. Based on current model assumptions and inputs, Figure 5-6 shows that approximately~~ [redacted] ~~of the time, PG&E would have a greater than~~ [redacted] ~~GWh deficit in meeting compliance for~~ [redacted]~~.~~

~~7.3~~7.3. Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales of surplus procurement. Consistent with the Commission's adopted RNS methodology, PG&E's physical net short and cost projections do not include any projected sales of bankable contracted deliveries. However, PG&E ~~will consider selling non-bankable~~ is proposing as a part of its 2016 RPS Plan a framework for assessing whether to hold or sell surplus RPS volumes ~~in its portfolio and, in doing so, may identify and propose in the future opportunities to secure value for its customers through the sale of bankable surplus procurement.~~. PG&E will update its physical RNS in future RPS Plans if it executes any such sale agreements ~~and will include in its optimized RNS and SONS specific future plans to sell RPS procurement~~.

~~8~~8. Margin of Procurement

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to: (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the ~~33~~50% RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

~~8.1~~8.1. Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[60] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[61]

As described in more detail in Section 6, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model (so long as deliveries commence within the allowed delay provisions in the contract). PG&E considers this deterministic result to be its current statutory margin of procurement.[62] However, as discussed in Sections 6 and 7, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

~~8.2~~8.2. Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin

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60 Cal. Pub. Util. Code § 399.13(a)(4)(D).

61 *Id.*, § 399.15(b)(5)(B)(iii).

62 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums. ~~However, its revised success rate assumption (from 87% to 99%) also reflects several recent contract terminations from PG&E's portfolio due to and an update to the "Closely Watched" category described in Section 6.~~

of procurement.[63] As discussed further in Sections 6 and 7, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

While PG&E's current optimization strategy projects [redacted]~~.~~the use of a portion of PG&E's projected Bank to meet compliance requirements [redacted], PG&E believes it would be imprudent to use its entire projected Bank toward meeting its RPS compliance, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, ~~the~~holding a minimum Bank will ~~help~~reduce non-compliance risk, helping to avoid long-term over-~~procurement~~compliance above the ~~33~~50% RPS target~~,~~ and~~ will~~ thus ~~reduce~~reducing long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 6 and 7.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

~~9~~9. Bid Selection Protocol

As described in Sections 3 and 7, PG&E is well positioned to meet its RPS targets, under ~~both~~ a ~~33~~50% RPS target~~ and a 40% RPS scenario~~, until at least

63 ~~*Id.*,§~~Cal. Pub. Util. Code § 399.13(a)(4)(D).

[redacted]. As a result, PG&E ~~will~~proposes not ~~issue~~to hold a ~~2015~~2016 RPS procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2016 and 2017 through other Commission-mandated programs, such as the ReMAT and ~~RAM~~BioRAM Programs. To reflect ~~that~~ PG&~~E will~~E's proposal not ~~issue~~to hold a ~~2015~~ 2016 RPS ~~Solicitation~~procurement solicitation, language has been added throughout the ~~final 2015~~2016 RPS Plan to confirm that PG&E is required to seek permission from the Commission to procure any renewable energy amounts during the time period covered by the ~~2015~~2016 RPS Plan, except for RPS amounts that are separately mandated. Thus, PG&E is not including in the 2016 RPS Plan a solicitation protocol for procuring additional RPS resources, nor is it including an evaluation methodology for such purchases.

~~In D.15-12-025, the Commission required in Ordering Paragraph 7 that PG&E "include a description of how their process ensures that there is no double counting between the Integration Cost adder and the Net Market Value components in the Least-Cost Best-Fit methodology of [its] RPS plan[]. . .." If PG&E were to procure RPS resources, there would be no double counting between the integration cost adder and the Net Market Value ("NMV") components in the Least-Cost Best-Fit ("LCBF") methodology that would be used by PG&E. NMV measures the cost of the renewable resource in terms of direct impacts on ratepayers—PPA payments to the supplier plus transmission costs and integration costs, less the energy and capacity value of the resource. It is associated with the marginal value of the energy and capacity produced directly by the resource—it is the market cost that PG&E no longer incurs because it is procuring energy and capacity from the resource instead. The integration cost represents the system costs that are incurred for *other* resources that are needed to support the additional renewable resource. The variable cost represents the incremental cost of running existing flexible units in the short term, and the fixed cost represents the incremental cost of additional flexible RA capacity to support the additional renewable resource.~~ PG&E has included in Section 19 below and in confidential Appendix J a description of the framework PG&E proposes to use to assess whether to hold or sell excess RPS volumes. If the Commission approves the proposed framework, PG&E expects to conduct one or more solicitations in 2017 for short-term sales of bundled RPS volumes. PG&E anticipates selling short-term products based on its position, and may consider longer term offers in the future. PG&E has included a solicitation protocol and *pro forma* sales agreement as Attachment I to this 2016 RPS Plan. The pro forma sales agreement is largely unchanged from the Power Purchase and Sale Agreement adopted in the 2014 RPS Plan. The draft protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price.

PG&E anticipates minimal negotiations with respect to the form sales agreement and proposes filing the sales agreement by Tier 1 Advice Letter for Commission approval. This approach is consistent with the streamlined Tier 1 Advice Letter process authorized in D.14-11-042 for short-term sales agreements. In that decision, the Commission determined that a Tier 1 Advice Letter process could be utilized[64] as long as a utility has included a pro forma short-term contract as part of its approved RPS plan filing and the contract term is under 5 years. Streamlined processes for both RFO administration and Commission approval are required in order to allow for transactions to begin in 2017.

~~9.1~~9.1. Proposed Time of Delivery Factors

PG&E sets its Time of Delivery ("TOD") factors based on expected hourly prices. Given the high penetration of solar generation expected through 2020 and beyond, PG&E forecasts that there will be significant periods of time during the mid~~-~~-day when net~~-~~ loads are low, resulting in prices that will be low or negative, especially in the spring. This expectation is consistent with forecasts of net load that have been

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[64] D.14-11-042, pp. 74-78, and implemented in PG&E's approved 2014 RPS Plan.

publicized by the CAISO.[65] In addition, given the low mid-day loads, PG&E sees its peak demand (and resulting higher market prices) moving to later in the day~~.~~, and as result, shifted its TOD periods in 2015. Capacity value has also become significantly less important in the selection process because: (1) market prices for generic capacity are low; and (2) net qualifying capacity using effective load carrying capability is also low. Thus, PG&E ~~would simplify~~simplified its PPAs in 2015 and ~~include~~included only a single set of TOD factors to be applied to both energy-only and fully deliverable resources.

PG&E is keeping TOD periods unchanged, but updating its TOD factors ~~and TOD periods~~ as follows:

~~New TODs~~

- ~~Move peak period from HE16-HE21 to HE17-HE22~~
- ~~Move mid-day period from HE07-HE15 to HE10-HE16~~
- ~~Move night period from HE22-HE06 to HE23-HE09~~
- ~~Move March back to the "Spring" period~~
- ~~Result: Summer=Jul.-Sep., Winter=Oct.-Feb., Spring=Mar.-Jun.; and Peak=HE17-HE22, Mid-day=HE10-HE16, Night=HE23-HE09~~

TABLE 9-1
RPS TIME OF DELIVERY FACTORS

	Peak	Mid-Day	Night
Summer	1.~~479~~515	0.~~604~~713	1.~~087~~003
Winter	1.~~399~~484	0.~~718~~674	1.~~122~~155
Spring	1.~~270~~109	0.~~280~~491	~~1.040~~0.926

65 *See*, *e.g.*, *CAISO Transmission Plan 2014-2015*, pp. 162-163 (approved March 27, 2015) (available at http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf).

9.2. Workforce Development

SB 2 (1X) added a requirement that the LCBF criteria for ranking and selecting RPS resources shall include "the employment growth associated with the construction and operation of eligible renewable energy resources."[66] The Ruling directs the IOUs to include a description of a proposed approach for assessing and differentiating the ability of different bids to contribute to employment growth during the construction and operational phases of the project.[67]

PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E's LCBF methodology does include a qualitative assessment of the extent to which the proposed development supports RPS goals. It is based on information provided by the Seller and PG&E's assessment of that information. If PG&E were procuring RPS resources, it would require bidders to submit information on projected California employment growth during construction and operation. This would include number of hires, duration of hire, and indication of whether the bidder has entered into Project Labor Agreements or Maintenance Labor Agreements in California for the proposed project. This information was required from bidders in PG&E's 2014 RPS RFO.[68]

9.3. Disadvantaged Communities

SB 2 (1X) also added the requirement that preference shall be given "to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse

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66 Cal. Pub. Util. Code § 393.13(a)(4)(A)(iv).

67 Ruling, p. 14.

68 Attachment J2 to 2014 RPS RFO Protocol.

gases."[69] The Ruling directs the IOUs to include a description of their methodology for preferring projects that provide those benefits.[70]

As explained above, PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E has included this component as part of its assessment of an offer's consistency with and contribution to California's goal for the RPS Program. PG&E's LCBF methodology includes a qualitative assessment of the extent to which the proposed development supports RPS goals is based on information provided by the Seller, and PG&E's assessment of that information.

If PG&E were procuring resources, it would expect to solicit information from bidders similar to what was required in the 2014 RPS RFO.[71] PG&E asked bidders to respond to the following questions on this topic:

> Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels? If so, the Participant is encouraged to describe in its Offer, if applicable, how its proposed facility can provide the following benefits to adjacent communities:
>
> - Projected hires from adjacent community (number and type of jobs),
> - Duration of work (during construction and operation phases),
> - Projected direct and indirect economic benefits to the local economy (i.e., payroll, taxes, services),
> - Emissions reduction - Identify existing generation sources by fuel source within 6 miles of proposed facility; Will the proposed facility replace/supplant identified generation sources?
>   - If "yes", provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much MWh/year), and avoided emissions released into the community (within 6 miles of the project).

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69 Cal. Pub. Util. Code § 399.13(a)(7).

70 Ruling, p. 15.

71 Attachment J2 to 2014 RPS RFO Protocol.

- If “No”, why not?

In D.04-07-029, the CPUC identified benefits to low income or minority communities, environmental stewardship, local reliability, repowering, and resource diversity as factors to be incorporated in PG&E’s Offer evaluation. The Participant is encouraged to describe in its Offer(s) how its Eligible Renewable Resource (“ERR”) facility can provide these benefits. If known, list any existing or proposed generation projects within a one-mile radius of the Project offered into this Solicitation.

~~10~~10. Consideration of Price Adjustment Mechanisms

The ~~ACR~~Ruling requires each IOU to “describe how price adjustments (e.g., index to key components, index to Consumer Price Index (“CPI”), price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date.”[72]

~~PG&E will~~In this 2016 RPS Plan, PG&E is proposing not to hold an RPS solicitation in 2016 and it does not plan to procure additional RPS volumes in 2017, other than through mandated programs. If PG&E was negotiating PPAs for additional procurement, PG&E might consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the legislature has found is a benefit of the RPS Program.[73] In order to maximize the RPS Program’s benefits to customers, cost risk should generally be borne by developers.

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72 ~~ACR~~Ruling, p. 15.

73 ~~*See*~~ Cal. Pub. Util. Code § 399.11(b)(5).

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the Commission's expressed desire to standardize and simplify RPS solicitation processes.[74]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the CPI. The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

~~11~~11. Economic Curtailment

In D.14-11-042, the Commission ~~approved curtailment terms and conditions for PG&E's pro forma RPS PPA.~~directed that the IOUs describe in future RPS Plans how "expected economic curtailment affects their RPS procurement."[75] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the Procurement Review Group ("PRG").[76] In ~~May~~

74 ~~*See*~~ D.11-04-030, pp. 33-34.

75 D.14-11-042, ~~pp. 43-44~~p. 45.

76 *Id*., pp. 42-43.

~~2015~~June 2016, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E's observations and issues related to economic curtailment both for the market generally, and PG&E's specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in ~~2015~~the first half of 2016 has ~~generally~~broadly increased in the Real-Time Markets~~, even during the low hydro conditions of 2015.~~ ("RTM") for the PG&E Default Load Aggregation Point ("DLAP") and for the North of Path 15 Hub ("NP15 Hub"). During January through ~~May 2015~~June 2016, negative price intervals in the CAISO Five Minute Market for the ~~North of Path 15 Hub~~ PG&E DLAP occurred ~~more than 1,800 times (4.2%~~ in approximately 6.6% of the 5~~-~~-minute intervals~~)~~, compared to ~~1,100 times (2.5%)~~approximately 4% during the same period in ~~2014~~2015. Similarly, ~~the ZP26~~ NP15 Hub prices for this period in ~~2015~~2016 were negative ~~over 4,100 times (9.5%), a substantial increase over the 2014~~approximately 6.8% of the 5-minute intervals compared to approximately 3.6% during this period in 2015. The ZP26 Hub prices for 2016 in this period were negative approximately 8.3% of the intervals, roughly equal to the 2015 results ~~of 1,400 times (3.3%). Increased negative price periods have led to increased curtailments of renewable resources that are economically bid~~for this same period. The specific occurrences of negative price periods and overgeneration events are largely unpredictable;

[redacted]

[redacted] [77] [redacted] PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. This also includes the incremental costs of compliance instruments required to comply with ~~the 33%~~ RPS ~~target~~targets. PG&E provided more detail concerning its RPS bidding strategy in its ~~proposed 2014~~ Bundled Procurement Plan ("BPP")[78] which was ~~filed with~~approved by the Commission in ~~October 2014 and is currently pending at the Commission.~~~~[79]~~D.15-10-031.

[redacted] [80] [redacted]

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77 [redacted]

78 See PG&E, 2014 Bundled Procurement Plan, Appendix K (Bidding and Scheduling Protocol).

~~79 See PG&E, *Proposed 2014 Bundled Procurement Plan*, R.13-12-010, Appendix K (Bidding and Scheduling Protocol) (October 3, 2014).~~

~~80~~ [redacted]

[redacted][81][redacted][82]

While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods and also ~~potentially enhancing~~ CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events.

With regard to longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. ~~Under the 33% RPS target, PG&E assumes curtailment~~ [redacted]~~[83] under a 40% RPS scenario, PG&E expects curtailment to increase in line with recent CAISO estimates~~ [redacted][84]

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81 [redacted]

82 [redacted]

~~83~~ [redacted]

84 [redacted]

These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed. Implementation of these assumptions in PG&E's modeling is discussed in more detail in Section 6.2.3.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in negative pricing events.

12. California Tree Mortality Emergency Proclamation

On October 30, 2015 the Governor declared a state of emergency to address epidemic tree mortality in California, stating that this epidemic mortality presents an enhanced threat to life, safety, and property from falling trees, and exacerbates wildfire risk.[85] The Emergency Proclamation is intended to mobilize resources for the safe removal of the hazardous trees. PG&E has been actively involved in the State's implementation of the Proclamation and remains committed to working closely with the Commission, California Department of Forestry and Fire Protection, Governor's Office, and all stakeholders to address this crisis.

Below, PG&E addresses the three issues identified in the Ruling related to the Emergency Proclamation.

[redacted]

[85] Ruling, pp. 16-17; see also Governor Brown's State of Emergency Proclamation, issued on October 30, 2015 (available at: https://www.gov.ca.gov/docs/10.30.15_Tree_Mortality_State_of_Emergency.pdf).

12.1. PG&E's Biomass Portfolio

PG&E's biomass portfolio, in Table 12-1 below, consists of two different types of contracts: legacy Standard Offer Qualifying Facility Power Agreements (QF PPA) or contracts entered into as a result of required Renewables Portfolio Standard procurement (RPS PPA). QF PPAs receive a payment for energy delivered and an additional capacity payment based on energy delivered during specific hours. The energy price paid to QFs is based upon a monthly Short-Run Avoided Cost calculation or a bilaterally negotiated price subsequently approved by the Commission. Prices for QFs shown in Table 12-1 represent historical costs for energy and delivered capacity expressed on a dollar per MWh basis. The RPS PPAs are paid a single all-in price for energy and capacity. The RPS prices shown represent the levelized price of energy included in the advice letter seeking approval of the transaction.

PG&E has entered into several contract amendments to respond to the Emergency Proclamation. On April 1, 2016, PG&E filed an advice letter asking the Commission to approve a contract amendment for five biomass facilities.[86] The advice letter was approved on June 9, 2016.[87] In addition, on June 3, 2016, PG&E filed advice letters asking the Commission to approve short-term extensions of the pricing amendments to existing QF PPAs with two biomass facilities.[88] The proposed amendments would further the goals of the Emergency Proclamation by helping to ensure that these two biomass facilities, which are located in areas of the state significantly impacted by tree mortality, will continue to operate and be available as a way to dispose of HHZ fuel through the end of the high forest fire danger season.

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86 See Advice Letter 4818-E.

87 See Commission Resolution E-4786.

88 See Advice Letter 4851-E.

TABLE 12-1
PG&E'S BIOMASS PORTFOLIO

Name	Contract Expiration Date	Capacity (MW)	City	County	QF Historical Payments Price or RPS Contract Price ($/MWh)	Maximum Price Under Price Amendment	Price Amendment Expiration Date
PG&E's QF and FIT Biomass Contracts[89]							
1. Pacific-Ultrapower Chinese Station (Ogden Power Pacific, Inc.)	1/23/2017	22	Jamestown	Tuolumne	93.42	$100.43	10/31/16
2. DG Fairhaven Power	2/2/2017	17.25	Fairhaven	Humboldt	104.52	$107.42	1/31/16
3. Wheelabrator Shasta	4/30/2018	54.9	Anderson	Shasta	94.65	$100.43	7/31/16
4. Rio Bravo Fresno	2/12/2019	26.5	Fresno	Fresno	98.77	$100.43	10/31/16
5. HL Power	9/15/2019	32	Wendel	Lassen	99.56	$101.26	7/31/16
6. Burney Forest Products	1/2/2020	31	Burney	Shasta	[redacted]	[redacted][90]	8/31/16
7. Rio Bravo Rocklin	3/16/2020	25	Rocklin	Placer	98.99	100.43	7/31/16
8. Thermal Energy Dev. Corp.	5/30/2020	21	Tracy	San Joaquin	98.82	N/A	N/A
9. Humboldt Redwood Company (Eel River Power Facility)	evergreen	22	Scotia	Humboldt	98.95	N/A	N/A
10. Ortigalita Power Company (1969/FiT)	6/16/2026	0.75	Merced	Merced	103.50	N/A	N/A
PG&E's RPS Biomass Contracts[91]							
11. Mt. Poso	2/20/2027	44	Bakersfield	Kern	141.12	N/A	N/A
12. El Nido Biomass Facility	2/8/2031	9	Merced	Merced	121.62	N/A	N/A
13. Chowchilla Biomass Facility	2/8/2031	9	Chowchilla	Madera	121.62	N/A	N/A
14. Wadham Energy LP	5/31/2018	26.5	Williams	Colusa	95.66	N/A	N/A
15. Woodland Biomass	2/29/2020	25	Woodland	Yolo	102.06	N/A	N/A
16. SPI Biomass Portfolio:[92] Burney Lincoln Quincy Sonora Anderson II	9/8/2035	58	Anderson Lincoln Quincy Sonora Anderson	Shasta Placer Plumas Tuolumne Shasta	[redacted]	N/A	N/A
DTE Stockton	2/20/2039	44.5	Stockton	San Joaquin	[redacted]	N/A	N/A

89 The QF and FIT payments shown in Table 12-1 represent the average historical costs for energy and delivered capacity expressed on a $/MWh basis for the years 2013-2015. This data is consistent with the payments reported in the annual Padilla data request for 2013-2015. Contracts 1-9 in Table 12-1 are QF contracts.

90 [redacted]

91 The RPS prices represent the levelized price of energy as represented in the advice letters seeking approval of these contracts.

92 On June 9, 2016, the Commission approved an amendment to PG&E's RPS contract with SPI which allows for up-to an additional 21 MW of capacity from the five existing biomass facilities. The incremental generation will be produced from fuel recovered in response to the Governor's Emergency Proclamation and other declared drought-related emergencies.

12.2. Benefits of Biomass Contracts in PG&E's Renewable Portfolio

12.2.1. Contribution to RPS

PG&E has historically been, and continues to be, the primary purchaser of electricity generated by in-state biomass resources. Biomass is an important component of PG&E's renewables portfolio. For example, in 2015, biomass represented nearly 14% of PG&E's RPS generation. PG&E procured over 90% of all biomass contracted to IOUs in California in 2015, and in 2016, PG&E expects to be the sole buyer of biomass among IOUs outside of the recently established targeted BioRAM procurement mechanism.[93] Additionally, because biomass resources contribute to its RPS compliance, PG&E renegotiated or restructured biomass PPAs to allow continued operations of several facilities in 2011. However, while biomass continues to play an important role in PG&E's diverse portfolio of resources, biomass projects are currently less competitive and less flexible than some alternative renewable energy sources. Furthermore, as described in Sections 3.3 and 7, as well as Appendix C, PG&E has no current need for incremental RPS-eligible procurement, including biomass procurement.

12.2.2. Portfolio Fit

While biomass facilities provide RPS-eligible energy, there are also significant operational challenges associated with biomass. For example, biomass is a baseload resource. This means that while generation output may be more predictable than for a variable resource (e.g., wind or solar), biomass resources have less ability than some other more flexible resources to adjust output levels in response to market or system conditions. As California moves towards meeting a 50% RPS, increased ramping capability will be needed to accommodate growing variability and uncertainty associated

93 See 2014 Preliminary Annual 33% RPS Compliance Report of Pacific Gas and Electric Company (Filed February 26, 2015); Southern California Edison Company's (U 338-E) 2014 Preliminary Annual 33% Renewables Portfolio Standard Compliance Report (Filed September 4, 2015); San Diego Gas and Electric Preliminary Annual 33% RPS Compliance Report (September 4, 2015).

with the integration of intermittent renewable resources. An increase in baseload capacity (such as biomass) that cannot be economically dispatched by the CAISO market may further increase the potential for overgeneration, since such inflexible capacity, if it has to be taken, would require the CAISO to economically or physically curtail generation from other resources in order to balance load and resources.

12.2.3. Societal Benefits

In addition to providing energy and contributing to the state's RPS targets, various social benefits are ascribed to biomass generation, including job preservation and wildfire hazard risk reduction. The Commission and the Governor have previously noted the potential for these benefits, and the Commission has developed BioRAM in response to the Proclamation. BioRAM utilizes the existing RAM process to mandate a minimum of 50 MW of biomass generation statewide in an attempt to provide additional disposal options for biomass fuel in the highest fire hazard zones of the State.

Although PG&E has played an active role in developing biomass procurement programs, any discussion of societal benefits should be part of a larger conversation focusing on how the state can foster a longer-term, sustainable structure for funding biomass investment. A sustainable funding structure would provide public funding equivalent to the value of these broader societal benefits; ensuring that everyone who benefits from these investments help bear the incremental costs and the burden is not borne solely by PG&E's customers. Additionally, if biomass procurement is designed to provide broad societal benefits to all electricity customers, as is the case with BioRAM, those benefits should be paid by all benefitting customers and not only by the IOUs' bundled customers. PG&E has jointly proposed an appropriate non-bypassable charge for this purpose as part of the BioRAM proceeding.[94]

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[94] See Joint Petition for Modification of D.10-12-048, filed in R.08-08-009 on April 19, 2016. Appendix 3 of the Petition provides a detailed description of the mechanics that should be used for a non-bypassable charge.

12.3. Additional Emergency Proclamation-Related Procurement Alternatives

To the extent that the Commission explores additional Emergency Proclamation-related procurement, it should be based on a clear demonstration of need. Specifically, this demonstration should be based on three findings. First, any future mandates should be based on a demonstration of both the currently identified volume of high hazard forest material that must be removed and a projection of the expected volumes that will be available over the anticipated contract terms (i.e., 5, 10, 15 or 20 years). Second, any such order should first consider the capacity and costs of all disposal options, not only electricity generation. This should specifically include an investigation regarding whether alternative end-uses (*e.g.,* conversion of biomass to biogas for direct injection into the pipeline or use in the transportation sector) are cost-effective and viable. Finally, any such mandate should first determine that the costs of additional biomass procurement should be allocated to all benefitting customers because the procurement will provide demonstrated, quantifiable, and commensurate benefits to all electricity customers.

As mentioned above, PG&E is currently the only IOU procuring biomass in the state outside of BioRAM. If additional Emergency Proclamation-related procurement is determined to be necessary based on all of the above findings, all LSEs must either be required to participate, or costs must be allocated to all benefitting customers in California on a fully non-bypassable basis.

Additionally, the terms of any contracts resulting from additional mandated Emergency Proclamation-related procurement should be no greater than five years. Because bark beetle infestation is driven by a host of outside factors, like temperature and precipitation levels, the length of the crisis cannot be known in advance. A five-year term is enough to provide a predictable disposal outlet, while not burdening customers with unnecessary costs once these issues are mitigated.

Finally, facilities with short-term contracts from Emergency Proclamation-related procurement should be, at a minimum, subject to the same fuel verification requirements set forth in Resolution E-4770, which established the BioRAM Program, in order to effectively address the emergency conditions raised in the Proclamation.

~~12~~13. Expiring Contracts

The ~~ACR~~Ruling requires PG&E to provide information on contracts expected to expire in the next 10 years.[95] Appendix E lists the projects under contract to PG&E that are expected to expire in the next 10 years. ~~The table includes the following data:~~

1. ~~PG&E Log Number~~
2. ~~Project Name~~
3. ~~Facility Name~~
4. ~~Contract Expiration Year~~
5. ~~Contract Capacity (MW)~~
6. ~~Expected Annual Generation (GWh)~~
7. ~~Contract Type~~
8. ~~Resource Type~~
9. ~~City~~
10. ~~State~~
11. ~~Footnotes identifying if PG&E has already secured the expiring volumes through a new PPA~~

As indicated in Appendix G, PG&E's RNS calculations assume no re-contracting. Re-contracting is not precluded by this assumption, but rather it reflects that proposed ~~material amendments (i.e., those needed to avoid project failure) or~~ extensions ~~to~~of existing contracts will be evaluated against current offers.

95 ~~ACR~~Ruling, p. ~~16~~17.

~~13~~14. Cost Quantification

This section summarizes results from actual and forecasted RPS generation costs (including incremental rate impacts), shows potential increased costs from mandated programs, and identifies the need for a clear cost containment mechanism to address RPS Program costs. Tables 1 through 4 in Appendix D provide an annual summary of PG&E's actual and forecasted RPS costs and Page 1 of Appendix D outlines the methodology for calculating the costs and generation.

~~13.1~~14.1. RPS Cost Impacts

Appendix D quantifies the cost of RPS-eligible procurement—both historical (2003-~~2014~~2015) and forecast (~~2015~~2016-2030). From 2003 to ~~2014~~2015, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E incurred more than [redacted] $2.4 billion in procurement costs for RPS-eligible resources in ~~2014~~2015.

RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate for RPS-eligible procurement and generation. While this formula does not provide an estimate of the renewable "above-market premium" that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix D illustrate the potential rate of growth in RPS costs and the impact this growth will have on average rates, all other factors being equal. Annual rate impact of the RPS Program increased from 0.7¢/kWh in 2003 to an estimated 3.~~5~~6¢/kWh in 2016, meaning the average rate impact from RPS-eligible procurement has increased more than five-fold in approximately ~~12~~13 years. This growth rate is projected to continue increasing through 2020, as the average rate impact is forecasted to increase to ~~3.9~~4.5¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs resulting from the direct procurement of the renewable resources, there are incremental indirect transmission and integration costs associated with that procurement.

~~13.2 Procurement Expenditure Limit~~

~~Section 399.15(f) provides that the Commission waive the RPS obligations of an electrical corporation once it meets the cost containment limitation, provided that additional resources cannot be procured without exceeding "a de minimis increase in rates." The methodology for the PEL, the Commission's cost containment mechanism, is still under development. As discussed in Section 2.2, PG&E looks forward to the Commission finalizing the PEL methodology and implementing it, to ensure that customers are adequately protected and promote regulatory certainty and support procurement planning.~~

~~13.3~~14.2. Cost Impacts Due to Mandated Programs

As PG&E makes progress toward achieving the 50% RPS goal ~~of 33%,~~, the cost impacts of mandated procurement programs that focus on particular technologies or project size increase over time, and procurement from those programs increasingly comprises a larger share of PG&E's incremental procurement goals. In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets that allow only a subset of those options.[96] Studies have also shown that renewable electricity mandates increase prices and costs,[97] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants; and second, by creating a less robust market for participants to compete.[98] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

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96 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et al., "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/RFF/Documents/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

97 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call" (available at http://www.instituteforenergyresearch.org/pdf/statereport.pdf); Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

98 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

~~14~~15. Imperial Valley

For the IOUs' 2014 RPS solicitations, the Commission did not specifically require any remedial measures to bolster procurement from Imperial Valley projects but required continued monitoring of IOUs' renewable procurement activities in the Imperial Valley area.[99] Even without remedial measures in PG&E's 2014 RPS Solicitation, the Independent Evaluator monitoring that solicitation found that:

> Overall, the response of developers to propose Imperial Valley projects was robust and PG&E's selection of Imperial Valley Offers was representative of that response. Arroyo perceives no evidence that PG&E failed in any way to perform outreach to developers active in the Imperial Valley or that there was any structural impediment in the RFO process that hindered the selection of competitively priced Offers for projects in the Imperial Valley.[100]

Given the robustness of the response from Imperial Valley projects in the 2014 RPS solicitation, as well as the 2013 RPS solicitation, and given the fact that PG&E is proposing not ~~planning on conducting~~to hold a ~~2015~~2016 RPS solicitation, there does not appear to be a need to adopt any special remedial measures for the Imperial Valley as a part of the RPS Plan.

~~The ACR also directs the IOUs to report on any CPUC-approved~~PG&E has one RPS PPA under contract for ~~projects~~a project in the Imperial Valley~~ that are under development, and any RPS projects in the Imperial Valley that have recently achieved commercial operation.[101] PG&E has one PPA under contract in the Imperial Valley.~~. That project is in development. Commercial operation is expected in ~~2016~~2017, with deliveries under the PPA beginning in 2020.

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[99] D.14-11-042, pp. 15-16.

[100] PG&E, *Advice Letter 4632-E*, p. 40, Section 2 (IE Report) (May 7, 2015).

~~[101] ACR, p. 19.~~

~~15~~16. Important Changes to Plans Noted

This section describes the most significant changes between PG&E's ~~2014 RPS Plan and its~~ 2015 RPS Plan and its Draft 2016 RPS Plan. A complete redline of the draft ~~2015~~2016 RPS Plan against PG&E's ~~2014~~2015 RPS Plan ~~was~~is included as Appendix A of the ~~August 4, 2015 draft~~2016 RPS Plan. ~~This section identifies and summarizes the key changes and differences between the 2014 RPS Plan and the proposed 2015 RPS Plan. Specifically, the~~The table below provides a list of key differences between the two RPS Plans:

Reference	Area of Change	Summary of Change	Justification
~~Section 1~~	~~Section format and structure~~	~~Remove "Executive Summary" from Introduction.~~	~~Ease of document flow.~~
Entire RPS Plan	Consideration of ~~a~~the Higher RPS ~~Requirement~~Requirements from SB 350	~~Include response~~Includes updates to ~~the Specific Requirements for 2015 RPS Procurement Plans, considering~~consider both the ~~current~~ 33% by 2020 target and ~~a 40% by 2024 scenario.~~an assumed "straight-line" trajectory associated with the SB 350 compliance period targets towards 50% RPS in 2030	~~ACR~~Ruling at pp. 4-5~~-6~~.
~~Section 2.1~~	~~Commission Implementation of SB 2 (1x)~~	~~Include discussion of D.14-12-023, setting RPS compliance and enforcement rules under SB 2 (1X).~~	~~ACR at p. 4.~~

Reference	Area of Change	Summary of Change	Justification
Section ~~3~~9.2~~.2~~	~~Impact of Green Tariff Shared Renewable Program~~Workforce Development	~~Include~~Includes discussion of ~~impact~~consideration of ~~Green Tariff Shared Renewable Program on RPS position.~~workforce development during bid evaluation	~~D.14-11-042; D.15-01-051.~~Ruling at p. 14
Section 9.3~~.4~~	~~Anticipated Renewable Energy Technologies and Alignment of Portfolio With Expected Load Curves and Durations~~Disadvantaged Communities	~~Include~~Includes discussion of ~~integration cost adder as part~~consideration of ~~LCBF~~disadvantaged communities during bid evaluation ~~methodology.~~	~~ACR~~Ruling at p. 15~~.~~
~~Section 3.5~~	~~RPS Portfolio Diversity~~	~~Include discussion of efforts to increase portfolio diversity.~~	~~ACR at p.10.~~
~~Section 5.4~~	~~Curtailment of RPS Generating Resources~~	~~Include discussion of economic curtailment as a potential compliance delay.~~	~~ACR at p.16.~~

Reference	Area of Change	Summary of Change	Justification
~~Section 11~~	~~Economic Curtailment~~	~~Include discussion of economic curtailment.~~	~~ACR at p.16.~~
~~Appendix C.1b~~	~~Renewable Net Short Calculations – 40% RPS Scenario~~	~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.~~	~~ACR at pp.5-6.~~
~~Appendix C.2b~~ Section 18	~~Alternate Renewable Net Short Calculations – 40% RPS Scenario~~California Tree Mortality Emergency Proclamation	Include response to the Specific Requirements for ~~2015~~2016 RPS Procurement Plans~~, considering both~~ related to the ~~current 33% by 2020 target and a 40% by 2024 scenario.~~Governor's Emergency Proclamation	~~ACR~~Ruling at ~~pp.5-6.~~ p. 16-17
~~Appendix F.2b~~	~~Project Failure Variability – 40% RPS Scenario~~	~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.~~	~~ACR at pp.5-6.~~
~~Appendix F.3b~~Section 19	RPS ~~Generation Variability – 40%~~ Position Management and Sales of Surplus RPS ~~Scenario~~ Products	~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.~~Includes discussion of a framework for assessing whether to hold or sell excess RPS volumes	~~ACR~~Ruling at ~~pp.5-6.~~p. 8
Appendix ~~F.4b~~J	~~RPS Deliveries Variability – 40% RPS Scenario~~Framework for Assessing Potential Sales of Excess RPS Volumes	~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.~~Includes a framework for assessing whether to hold or sell excess RPS volumes	~~ACR~~Ruling at ~~pp.5-6.~~p. 8
~~Appendix F.5b~~	~~RPS Target Variability – 40% RPS Scenario~~	~~Include response to the Specific Requirements for 2015 RPS Procurement Plans, considering both the current 33% by 2020 target and a 40% by 2024 scenario.~~	~~ACR at pp.5-6.~~

~~16~~17. Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

~~16.1~~17.1. Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its ~~2015~~2016 RPS Plan to develop additional utility-~~-~~owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct describes the safety of the public, employees and contractors as PG&E's highest priority.[102] PG&E's commitment to a safety-~~-~~first culture is reinforced with its Safety Principles, PG&E's Safety Commitment, Personal Safety Commitment and Keys to Life.[103] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental

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102 *See* PG&E, "Employee Code of Conduct" (August 2013) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 3 (available at http://www.pgecorp.com/aboutus/ethics_compliance/con_con_ven/).

103 *See* PG&E, "Employee Code of Conduct" *supra* (describing the Safety Principles, Safety Commitment, Personal Safety Commitment and Keys to Life).

authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E's testimony in its General Rate Case ("GRC"),[104] the top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ("OSHA") and the CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

With regard to employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance.

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104 *See* PG&E, *Prepared Testimony, ~~2014~~2017 GRC, Application ~~12-11-009,~~ 15-09-001,* Exhibit (PG&E-~~6~~5), Energy Supply, pp. 1-~~11, 2-17, 2-44, 2-66, 4-13~~18 to 1-19 (available at http://www.pge.com/regulation/).

Employees also participate in an employee led Driver Awareness Team established for the sole purpose of improving driving. An annual motor vehicle incident ("MVI") Action Plan is developed and implemented each year. This action plan focuses on vehicle safety culture and implements the Companywide motor vehicle safety initiatives in addition to specific tools such as peer driving reviews and 1 800 phone number analysis to reduce MVIs.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Training and ~~re certification~~recertification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Employee injury case management
- Safety performance recognition
- Public safety awareness

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. With regard to public safety, PG&E ~~is developing~~has developed and ~~implementing~~implemented a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

PG&E will never be satisfied in its safety performance until there is never an injury to any of its employees, contractors, or members of the public. Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement change that can improve safety~~-~~ performance.

~~16.2~~17.2. Development and Operation of Third-Party–Owned, RPS-Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. While this authority has not changed, PG&E ~~intends to add~~developed additional contract provisions~~ to its contract forms~~ to reinforce the developer's obligations to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities. Additionally, the new provisions will seek to implement lessons learned and instill a continuous improvement safety culture that mirrors PG&E's approach to safety.

Specifically, the safety language that PG&E ~~is developing~~has developed builds upon the former standard of Good Utility Practices to a new standard of Prudent ~~Utility~~Electrical Practices, which includes greater detail on the types of activities covered by this standard, including but not limited to safeguards, equipment, personnel training, and control systems. This language was included in the recently executed 2014 Energy Storage agreements and could be incorporated in future RPS form PPAs if PG&E's RPS position resulted in a need for RPS procurement.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

PG&E receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including OSHA recordables and work stoppage information. Additionally, the new contract provisions would require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. If the generator has repeated safety violations or challenges, the generator could be at greater risk of failing to meet a key project development milestone or failing to meet a material obligation set forth in the PPA.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

~~17~~18. Energy Storage

AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E submitted an application to procure energy storage resources on February 28, 2014. In D.14-10-045, the ~~CPUC~~Commission approved PG&E's application with modifications. PG&E filed final storage RFO results for ~~CPUC~~Commission approval on December 1, 2015~~. In addition,~~, and is awaiting Commission action on its Application. PG&E is also participating in a new proceeding, R.15-03-011, which the Commission opened in March 2015 to consider policy and implementation refinements to the energy storage procurement framework and program design. On March 1, 2016, PG&E submitted an application to procure storage as part of its 2016 Energy Storage RFO.

PG&E considers eligible energy storage systems to help meet its Energy Storage Program targets through its RPS procurement process, Energy Storage RFO, as well as other CPUC programs and channels such as the Self-Generation Incentive Program. PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[105]

19. RPS Position Management and Sales of Surplus RPS Products

As described in Section 7.2, PG&E forecasts its cumulative Bank to exceed the calculated minimum Bank size over the next ten years, in part due to changes to PG&E's retail sales forecast. Given this long position, PG&E is proposing a framework through which to assess whether PG&E should hold or sell excess bankable RPS volumes, and is requesting approval of this framework, detailed in Appendix J.

[redacted]

[redacted]:

- [redacted];
- [redacted][106]
- [redacted]

[105] *See* PG&E, *Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Resources (2014-2015 Biennial Cycle*~~), (available at: http://www.cpuc.ca.gov/NR/rdonlyres/D9CACD21-AB1C-411A-8B79-84FB28E88C58/0/PGE_StorageApplication.pdf).~~): http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=3100).

[106] [redacted]

[redacted]

Based on current inputs to the framework described in Appendix J, PG&E expects to hold one or more solicitations for the sale of bankable, bundled renewable generation and RECs in 2017. PG&E anticipates selling short-term products based on its position, and may consider longer term offers in the future.

While PG&E will execute sales through solicitations, PG&E may simultaneously consider entering into bilateral contracts, and would seek additional approval from the Commission under those circumstances. Confidential Appendix I contains PG&E's proposed sales solicitation protocol and pro forma sales agreement. The pro forma sales agreement is largely unchanged from the Power Purchase and Sale Agreement adopted in the 2014 RPS Plan. The draft protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price. PG&E anticipates minimal negotiations with respect to the form agreement and proposes that these sales agreements be filed as Tier 1 Advice Letters for Commission approval.

APPENDIX B

Project Development Status Update

~~January 14~~August 8, 2016

APPENDIX C.~~1a~~1

Renewable Net Short Calculations~~ – 33% RPS Target~~

~~January 14~~August 8, 2016

APPENDIX C.~~2a~~2

Alternate Renewable Net Short Calculations~~ – 33% RPS Target~~

~~January 14~~August 8, 2016

APPENDIX D

Procurement Information Related to Cost Quantification

~~January 14~~August 8, 2016

Appendix D – Procurement Information Related to Cost Quantification

Assumptions	
Table 1 (Actual Costs, $) Items	**Actual**
Rows 2 -- 8, 11 (2003-~~2014~~2015)[1,2,3,4,5~~,6~~]	Settled contract costs with all RPS-eligible contracts in PG&E's portfolio for 2003-~~2014~~2015
Row 9	For 2003-2011, capital costs are based on the net book value of PG&E's RPS-~~-~~eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14%. For~~-~~ 2012 through ~~2014~~2015, capital costs are based on the net book value of PG&E's RPS-~~-~~eligible units as of December of that respective year multiplied by a fixed charge rate of 14%. PG&E's actual operation and maintenance (O&M) costs for each year (2003-~~2014~~2015) were added to each year's capital costs to calculate total costs.
Row 10	LCOE for each project multiplied by the project's historical generation
Row 13	PG&E actual bundled retail sales
Row 14	Total Cost / Bundled Retail Sales (Row 12 / Row 13)
Table 2 (Forecast Costs, $) Items	**Forecast**
Rows 2 -- 8, 11, 16 -- 22, ~~25~~25[6]	PG&E's future expenditures on all RPS-eligible procurement and generation ~~either (1)~~ approved to date~~ or (2) executed prior to~~. 2016-2030 forecast uses April ~~2015 but pending CPUC approval. 2015 data represent a September 2014~~2016 vintage ~~and 2016-2030~~contract data~~ represent a ~~. January-April 2016 uses December 2015 vintage ~~to be~~forward price curve data. May 2016-2030 uses April 2016 forward price curve data. May 2016 - 2017 forecast data are consistent with the ~~2015 Integrated Energy Policy Report (IEPR).~~ 2017 ERRA forecast filing.
Rows 9 and 23	For ~~2015~~2016-2030, annualized capital costs based on the net book value of PG&E's RPS-~~-~~eligible units as of December ~~2014~~2015 were added to operation and maintenance (O&M) costs, which were calculated as ~~2014~~2015 O&M costs escalated at 5% annually for each year.
Row 10 and 24	LCOE for each project multiplied by the project's forecasted generation
Rows 13 and 27	PG&E bundled retail sales forecast
Rows 14 and 28	Total Cost / Bundled Sales
Row 29	Row 14 + Row 28
Table 3 (Actual Generation, MWh) Items	**Actual**
Rows 2 -- 11[1,3,4,5,6]	Generation (MWh) associated with payments for RPS-eligible deliveries
Table 4 (Forecast Generation, MWh) Items	**Forecast**
Rows 2 -- 11 and 16-25	Forecasted RPS-eligible generation (MWh) either (1) approved to date or (2) executed prior to April ~~2015~~2016 but pending Commission approval -- assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. ~~2015 data represent a September 2014 vintage and 2016-2030 data represent a April 2015 vintage to be consistent with the 2015 Integrated Energy Policy Report (IEPR).~~ 2016-2030 uses April 2016 contract vintage.

[1] ~~2014~~ 2015 Generation and Costs were updated to reflect best available data as of ~~March 2015~~April 2016.

[2] Row 5 includes the aggregate costs (specifically debt service and operation and maintenance) of PG&E's contract with Solano Irrigation District (SID) who supplies power from multiple hydro units, 100% of which are RPS-eligible. ~~SID's costs include the costs to operate and maintain the hydro units and project facilities (dams and waterways).~~ Yuba County Water Agency (YCWA) does not operate any RPS-eligible hydro units, therefore YCWA cost data is not relevant and thereby not included.

[3] RPS-eligible generation reported in ~~2014~~2015 is the best available settlements data as of ~~March~~ April 2016. Settlements~~2015 and therefore contains actual data as settlements~~ data for the prior year can continue to be adjusted after January of the current year. ~~As UOG Hydro and UOG Solar estimates are calculated separately, 2013 data for these two technology types is the best available as of April 2014.~~

[4] Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.

[5] Cost for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology specific costs based on the technology specific generation (MWh) of the sale contract.

[6] UOG Small Hydro generation for 2013-2015 has been updated to reflect actual settlements data.

~~[6] Some immaterial changes have been made to cost and generation data from 2005, 2011, and 2013 as compared to the 2014 RPS Plan. 2005 changes are due to a 2006 RPS wind contract being accidently included in 2005. 2011 data changes are due to a mislabeling of a biogas contract as biomass. 2013 changes represent updated settlements data.~~

Appendix D – Procurement Information Related to Cost Quantification

Note: As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 1
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs												
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
2	Biogas	$25,762	$23,856	$25,623	$22,823	$24,126	$23,468	$27,306	$20,216	$16,776	$5,333	$5,063	$11,087	$22,283
3	Biomass	$215,078	$217,923	$217,279	$222,125	$238,524	$259,957	$262,086	$263,994	$245,622	$302,711	$299,205	$317,301	$286,766
4	Geothermal	$110,572	$111,778	$108,720	$118,523	$199,143	$282,227	$200,357	$260,053	$223,575	$209,854	$284,334	$324,050	$280,843
5	Small Hydro	$60,984	$57,470	$80,340	$97,340	$63,161	$72,488	$52,053	$63,296	$84,864	$54,140	$57,213	$45,522	$34,247
6	Solar PV	$0	$0	$0	$0	$0	$0	$2,554	$10,180	$33,370	$176,372	$504,860	$803,806	$949,556
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,698	$173,856	$296,915
8	Wind	$65,244	$74,912	$56,891	$67,116	$98,203	$102,516	$199,475	$224,089	$340,517	$379,416	$424,764	$437,159	$422,102
9	UOG Small Hydro	$44,936	$45,059	$46,526	$47,556	$47,933	$49,009	$47,567	$49,684	$52,099	$51,572	$64,691	$66,066	$74,770
10	UOG Solar	$0	$0	$0	$0	$227	$452	$473	$1,498	$5,620	$27,093	$43,882	$52,426	$49,535
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	~~xxxx~~ $823	~~xxxx~~ $871	~~xxxx~~ $677	~~xxxx~~ $805	$704.86
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$522,576**	**$530,998**	**$535,380**	**$575,483**	**$671,317**	**$790,116**	**$791,870**	**$893,010**	~~xxxxxxxxx~~ **$1,003,268**	~~xxxxxxxxx~~ **$1,207,361**	~~xxxxxxxxx~~ **$1,686,387**	~~xxxxxxxxx~~ **$2,232,077**	**$2,417,720**
13	Bundled Retail Sales [Thousands of kWh]	71,099,363	72,113,608	72,371,532	76,356,279	79,078,319	81,523,859	79,624,479	77,485,129	74,863,941	76,205,120	75,705,039	74,546,865	72,112,848
14	**Incremental Rate Impact[2]**	**0.73 ¢/kWh**	**0.74 ¢/kWh**	**0.74 ¢/kWh**	**0.75 ¢/kWh**	**0.85 ¢/kWh**	**0.97 ¢/kWh**	**0.99 ¢/kWh**	**1.15 ¢/kWh**	~~xxxxxxx~~ **1.34 ¢/kWh**	~~xxxxxxxx~~ **1.58 ¢/kWh**	~~xxxxxxxx~~ **2.23 ¢/kWh**	~~xxxxxxxx~~ **2.99 ¢/kWh**	**3.35 ¢/kWh**

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row. For example, the cost of an Unbundled REC procured from a wind facility is only reported in the Unbundled RECs row.

[2] Incremental Rate Impact is equal to Row 12 divided by Row 13. While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs					
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	~~**2015**~~	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	~~$0~~	$0	$0	$0	$0	$0
3	Biomass	~~$0~~	$0	$0	$0	$0	$0
4	Geothermal	~~$0~~	$0	$0	$0	$0	$0
5	Small Hydro	~~$0~~	$0	$0	$0	$0	$0
6	Solar PV	~~$0~~	$0	$0	$0	$0	$0
7	Solar Thermal	~~$0~~	$0	$0	$0	$0	$0
8	Wind	~~$0~~	$0	$0	$0	$0	$0
9	UOG Small Hydro	~~$0~~	$0	$0	$0	$0	$0
10	UOG Solar	~~$0~~	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	~~$0~~	$0	$0	$0	$0	$0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	~~**$0**~~	**$0**	**$0**	**$0**	**$0**	**$0**
13	Bundled Retail Sales [Thousands of kWh]	~~71,182,544~~	~~70,869,576~~ 68,906,299	~~xxxxxxxxx~~ 67,126,317	~~64,956,724~~ xxxxxxxxxx	~~62,381,387~~ xxxxxxxxxx	~~59,668,061~~ 51,155,993
14	**Incremental Rate Impact[2]**	~~**0.000 ¢/kWh**~~	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	~~**2015**~~	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	~~$22,780~~	~~$23,189~~ $27,720	~~$29,915~~ $30,066	~~$29,994~~ $29,854	~~$29,986~~ $29,872	~~$30,143~~ $30,064
17	Biomass	~~$311,380~~	~~$270,577~~ $273,857	~~$241,040~~ $249,580	~~$219,990~~ $218,487	~~$193,377~~ $195,821	~~$136,275~~ $140,950
18	Geothermal	~~$329,015~~	~~$311,371~~ $283,645	~~$314,874~~ $289,770	~~$193,171~~ $179,115	~~$194,611~~ $180,105	~~$196,294~~ $182,193
19	Small Hydro	~~$76,539~~	~~$71,939~~ $68,801	~~$62,257~~ $63,191	~~$55,181~~ $55,056	~~$52,386~~ $52,168	~~$43,648~~ $47,629
20	Solar PV	~~$887,525~~	~~$914,533~~ $910,489	~~$970,536~~ $956,374	~~$974,319~~ $978,708	~~$1,000,120~~ $1,043,925	~~$1,019,418~~ $1,051,761
21	Solar Thermal	~~$329,978~~	~~$329,961~~ $327,058	~~$329,165~~ $326,270	~~$328,838~~ $325,944	~~$328,759~~ $325,865	~~$330,446~~ $327,539
22	Wind	~~$449,274~~	~~$432,664~~ $429,794	~~$427,910~~ $427,906	~~$425,276~~ $425,240	~~$408,949~~ $408,982	~~$409,845~~ $409,878
23	UOG Small Hydro	~~$67,407~~	~~$68,815~~ $76,353	~~$70,294~~ $78,016	~~$71,847~~ $79,762	~~$73,477~~ $81,595	~~$75,189~~ $83,520
24	UOG Solar	~~$51,674~~	~~$51,406~~ $51,288	~~$51,139~~ $51,022	~~$50,874~~ $50,757	~~$50,610~~ $50,494	~~$50,347~~ $50,232
25	Unbundled RECs[1]	~~xxxx~~	~~$0~~ $0	~~$0~~ $0	~~$0~~ $0	~~$0~~ $0	~~$0~~ $0
26	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25]	~~**xxxxxxxx**~~	~~**$2,474,455**~~ **$2,449,005**	~~**xxxxxxxxx**~~ **$2,472,193**	~~**$2,349,489**~~ **$2,342,923**	~~**$2,332,276**~~ **$2,368,828**	~~**$2,291,605**~~ **$2,323,765**
27	Bundled Retail Sales [Thousands of kWh]	~~71,182,544~~	~~70,869,576~~ 68,906,299	~~xxxxxxxxx~~ 67,126,317	~~64,956,724~~ xxxxxxxxx	~~62,381,387~~ xxxxxxxxx	~~59,668,061~~ 51,155,993

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2
(Forecast Costs, $ Thousands)

28	**Incremental Rate Impact**[2]	[redacted]	~~3.49 ¢/kWh~~ 3.55 ¢/kWh	~~xxxxxxxxx~~ 3.68 ¢/kWh	[redacted]	[redacted]	~~3.84 ¢/kWh~~ 4.54 ¢/kWh
29	**Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]	[redacted]	~~3.49 ¢/kWh~~ 3.55 ¢/kWh	~~xxxxxxxxx~~ 3.68 ¢/kWh	[redacted]	[redacted]	~~3.84 ¢/kWh~~ 4.54 ¢/kWh

1 See footnote 1 from Table 1.

2 Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs									
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
13	Bundled Retail Sales [Thousands of kWh]	~~59,779,916~~ 48,226,979	~~59,888,425~~ 45,611,218	~~59,987,654~~ 44,285,751	~~60,077,196~~ 43,549,939	~~60,188,640~~ 43,094,448	~~60,407,333~~ 42,750,940	~~60,765,057~~ 42,499,122	~~61,330,567~~ 42,456,543	~~62,066,738~~ 42,569,098	~~62,947,785~~ 42,853,116
14	**Incremental Rate Impact**[2]	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
16	Biogas	~~$30,098~~ $30,025	~~$30,190~~ $30,131	~~$30,175~~ $30,144	~~29,839~~ $29,837$	~~$29,408~~ $29,407	~~$29,107~~ $29,113	~~$29,167~~ $29,173	~~$29,288~~ $29,294	~~$27,193~~ $27,196	$26,884
17	Biomass	~~$127,551~~ $132,619	~~$128,345~~ $133,591	~~$129,109~~ $134,548	~~$130,224~~ $135,832	~~$130,865~~ $136,568	~~$131,575~~ $137,398	~~$99,946~~ $105,902	~~$95,123~~ $101,186	~~$95,038~~ $101,224	~~$95,228~~ $101,525
18	Geothermal	~~$196,819~~ $181,802	$13,563	$13,470	$13,423	$13,314	$13,256	$13,174	$13,121	$12,997	$12,921
19	Small Hydro	~~$35,937~~ $36,595	~~$29,846~~ $30,605	~~$29,039~~ $29,833	~~$29,202~~ $30,102	~~$28,968~~ $29,802	~~$29,258~~ $30,151	~~$29,666~~ $30,533	~~$29,695~~ $30,607	~~$24,716~~ $25,575	~~$24,619~~ $25,294
20	Solar PV	~~$1,015,955~~ $1,048,293	~~$1,013,201~~ $1,045,504	~~$1,009,278~~ $1,041,549	~~$1,007,457~~ $1,039,756	~~$1,004,547~~ $1,036,757	~~$1,005,450~~ $1,037,632	~~$1,001,743~~ $1,033,899	~~$1,000,015~~ $1,032,206	~~$992,076~~ $1,024,188	~~$988,605~~ $1,020,698
21	Solar Thermal	~~$329,547~~ $326,648	~~$329,514~~ $326,616	~~$329,165~~ $326,270	~~$329,232~~ $326,334	~~$329,063~~ $326,167	~~$329,978~~ $327,075	~~$329,547~~ $326,648	~~$329,639~~ $326,738	~~$328,838~~ $325,944	~~$328,759~~ $325,865
22	Wind	~~$403,463~~ $403,498	~~$397,706~~ $397,741	~~$378,153~~ $378,189	~~$353,862~~ $353,898	~~$351,789~~ $351,826	~~$287,146~~ $287,184	~~$287,350~~ $287,389	~~$288,065~~ $288,103	~~$251,628~~ $251,668	~~$250,960~~ $251,001
23	UOG Small Hydro	~~$76,987~~ $85,541	~~$78,874~~ $87,663	~~$80,856~~ $89,891	~~$82,937~~ $92,230	~~$85,122~~ $94,687	~~$87,416~~ $97,266	~~$89,825~~ $99,975	~~$92,354~~ $102,819	~~$95,010~~ $105,805	~~$97,798~~ $108,940
24	UOG Solar	~~$50,086~~ $49,972	~~$49,826~~ $49,712	~~$49,568~~ $49,455	~~$49,311~~ $49,198	~~$49,055~~ $48,943	~~$48,801~~ $48,689	~~$48,548~~ $48,437	~~$48,296~~ $48,185	~~$48,045~~ $47,935	~~$47,796~~ $47,687
25	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 16 through 25]	**~~$2,266,444~~ $2,294,992**	**~~$2,071,066~~ $2,115,126**	**~~$2,048,814~~ $2,093,348**	**~~$2,025,487~~ $2,070,610**	**~~$2,022,129~~ $2,067,470**	**~~$1,961,985~~ $2,007,764**	**~~$1,928,966~~ $1,975,129**	**~~$1,925,595~~ $1,972,259**	**~~$1,875,541~~ $1,922,533**	**~~$1,873,571~~ $1,920,815**
27	Bundled Retail Sales [Thousands of kWh]	~~59,779,916~~ 48,226,979	~~59,888,425~~ 45,611,218	~~59,987,654~~ 44,285,751	~~60,077,196~~ 43,549,939	~~60,188,640~~ 43,094,448	~~60,407,333~~ 42,750,940	~~60,765,057~~ 42,499,122	~~61,330,567~~ 42,456,543	~~62,066,738~~ 42,569,098	~~62,947,785~~ 42,853,116

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

28	**Incremental Rate Impact**[2]	~~3.79 ¢/kWh~~ 4.76 ¢/kWh	~~3.46 ¢/kWh~~ 4.64 ¢/kWh	~~3.42 ¢/kWh~~ 4.73 ¢/kWh	~~3.37 ¢/kWh~~ 4.75 ¢/kWh	~~3.36 ¢/kWh~~ 4.80 ¢/kWh	~~3.25 ¢/kWh~~ 4.70 ¢/kWh	~~3.17 ¢/kWh~~ 4.65 ¢/kWh	~~3.14 ¢/kWh~~ 4.65 ¢/kWh	~~3.02 ¢/kWh~~ 4.52 ¢/kWh	~~2.98 ¢/kWh~~ 4.48 ¢/kWh
29	**Total Incremental Rate Impact** [Row 14 + 28; Rounding can cause Row 29 to differ from Row 14 + 28]	~~3.79 ¢/kWh~~ 4.76 ¢/kWh	~~3.46 ¢/kWh~~ 4.64 ¢/kWh	~~3.42 ¢/kWh~~ 4.73 ¢/kWh	~~3.37 ¢/kWh~~ 4.75 ¢/kWh	~~3.36 ¢/kWh~~ 4.80 ¢/kWh	~~3.25 ¢/kWh~~ 4.70 ¢/kWh	~~3.17 ¢/kWh~~ 4.65 ¢/kWh	~~3.14 ¢/kWh~~ 4.65 ¢/kWh	~~3.02 ¢/kWh~~ 4.52 ¢/kWh	~~2.98 ¢/kWh~~ 4.48 ¢/kWh

1 See footnote 1 from Table 1.

2 Incremental Rate Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled “Incremental Rate Impact,” the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable “premium.” In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 3
(Actual Generation, MWh)

		Actual RPS-Eligible Procurement and Generation (MWh)												
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
2	Biogas	364,745	333,897	366,514	300,943	293,147	280,795	342,362	306,909	284,129	112,153	85,706	112,161	212,975
3	Biomass	2,839,795	2,961,633	2,858,643	2,770,398	2,751,813	2,813,819	3,122,048	2,990,615	3,043,656	3,158,131	3,055,370	3,226,904	2,814,468
4	Geothermal	1,674,702	1,753,043	1,687,360	1,790,870	2,701,970	3,350,232	3,411,798	3,766,700	3,780,954	3,807,728	3,687,236	3,870,952	3,646,936
5	Small Hydro	1,269,233	1,096,183	1,457,339	1,760,707	927,879	945,921	937,626	1,092,707	1,457,714	863,606	652,953	400,300	304,368
6	Solar PV	6	4	4	3	1	1	21,706	58,593	179,171	1,006,145	3,358,366	5,266,030	6,260,429
7	Solar Thermal	0	0	0	0	0	0	0	0	0	0	20,581	878,905	1,557,412
8	Wind	940,239	1,078,579	874,204	1,019,451	1,374,337	1,439,796	2,557,988	2,981,660	4,395,377	4,515,452	4,924,052	5,358,546	5,418,594
9	UOG Small Hydro	1,382,934	1,267,084	1,403,130	1,437,196	984,607	993,266	1,103,017	1,157,077	1,254,638	948,734	~~1,394,189~~ 929,639	~~1,292,552~~ 580,990	537,838
10	UOG Solar	0	0	0	0	225	445	504	4,642	26,790	165,656	279,500	336,905	318,582
11	Unbundled RECs2	0	0	0	0	0	0	0	0	102,888	108,874	101,256	100,581	88,107
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11]	8,471,654	8,490,423	8,647,195	9,079,568	9,033,979	9,824,276	11,497,048	12,358,903	14,525,317	14,686,479	~~17,559,209~~ 17,094,659	20,~~843,836~~ 132,274	21,159,709

1 Energy Volumes reported for ~~2014~~2015 in Rows 2 – 11 are the best available settlements data as of ~~March 2015~~April 2016.

2 Row 11 only includes Unbundled RECs with CPUC approval.

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 4
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries 2015-2020 (MWh)					
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	~~**2015**~~	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	~~0~~	0	0	0	0	0
3	Biomass	~~0~~	0	0	0	0	0
4	Geothermal	~~0~~	0	0	0	0	0
5	Small Hydro	~~0~~	0	0	0	0	0
6	Solar PV	~~0~~	0	0	0	0	0
7	Solar Thermal	~~0~~	0	0	0	0	0
8	Wind	~~0~~	0	0	0	0	0
9	UOG Small Hydro	~~0~~	0	0	0	0	0
10	UOG Solar	~~0~~	0	0	0	0	0
11	Unbundled RECs	~~0~~	0	0	0	0	0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11]	~~0~~	0	0	0	0	0
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	~~**2015**~~	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	~~213,398~~	~~215,310~~ 251,523	~~267,185~~ 266,995	~~267,182~~ 266,993	~~266,495~~ 266,306	~~266,549~~ 266,360
17	Biomass	~~3,040,682~~	~~2,872,745~~ 2,901,274	~~2,656,538~~ 2,734,501	~~2,351,353~~ 2,415,737	~~1,955,668~~ 2,044,887	~~1,217,664~~ 1,306,885
18	Geothermal	~~3,940,027~~	3,846,522	3,835,023	2,319,523	2,318,615	2,324,132
19	Small Hydro	~~1,055,888~~	~~919,433~~ 1,027,686	~~830,771~~ 918,985	~~756,106~~ 799,965	~~709,157~~ 728,760	~~612,327~~ 626,492
20	Solar PV	~~6,034,593~~	~~6,312,470~~ 6,261,500	~~7,065,526~~ 6,927,812	~~7,111,196~~ 7,271,865	~~7,454,367~~ 8,119,786	~~7,611,582~~ 8,160,001
21	Solar Thermal	~~1,780,838~~	~~1,783,858~~ 1,765,243	~~1,780,838~~ 1,762,261	~~1,780,838~~ 1,762,261	~~1,780,838~~ 1,762,261	~~1,783,858~~ 1,765,243
22	Wind	~~5,712,775~~	~~5,479,845~~ 5,448,391	~~5,383,493~~ 5,383,493	~~5,327,732~~ 5,327,732	~~5,122,748~~ 5,122,748	~~5,121,450~~ 5,121,450
23	UOG Small Hydro	~~1,251,112~~	~~1,151,280~~ 1,528,272	~~1,361,309~~ 1,334,249	~~1,433,494~~ 1,563,122	~~1,457,994~~ 1,498,509	~~1,470,682~~ 1,482,998
24	UOG Solar	~~343,413~~	~~330,121~~ 329,769	~~327,677~~ 328,054	~~325,972~~ 326,347	~~324,276~~ 324,649	~~323,304~~ 322,961
25	Unbundled RECs	~~100,000~~	0	0	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25]	~~23,472,725~~	~~22,911,584~~ 23,360,181	~~23,508,361~~ 23,491,374	~~21,673,397~~ 22,053,545	~~21,390,159~~ 22,186,523	~~20,731,551~~ 21,376,523

Appendix D – Procurement Information Related to Cost Quantification

Joint IOU Cost Quantification Table 4 (continued)
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries 2021-2030 (MWh)									
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	0	0	0	0	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0	0	0	0	0
4	Geothermal	0	0	0	0	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0	0	0	0	0
6	Solar PV	0	0	0	0	0	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0	0	0	0	0	0
8	Wind	0	0	0	0	0	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0	0	0	0	0	0
12	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 11]	0	0	0	0	0	0	0	0	0	0
15	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
16	Biogas	~~265,270~~ 265,082	~~265,284~~ 265,094	~~264,803~~ 264,638	~~261,746~~ 261,585	~~256,235~~ 256,076	~~251,874~~ 251,715	~~251,827~~ 251,667	~~252,519~~ 252,358	~~240,795~~ 240,635	~~238,613~~ 238,453
17	Biomass	~~1,090,072~~ 1,179,300	~~1,090,072~~ 1,179,327	~~1,090,072~~ 1,179,385	~~1,092,821~~ 1,182,006	~~1,090,072~~ 1,179,336	~~1,087,042~~ 1,176,297	~~882,505~~ 971,733	~~851,855~~ 941,134	~~849,722~~ 938,989	~~849,722~~ 938,941
18	Geothermal	2,316,815	152,229	151,342	150,941	149,584	148,713	147,846	147,454	146,129	145,278
19	Small Hydro	~~498,763~~ 510,274	~~413,322~~ 424,593	~~392,430~~ 403,033	~~391,039~~ 402,568	~~384,319~~ 394,368	~~383,913~~ 394,630	~~383,483~~ 393,599	~~378,818~~ 389,557	~~333,264~~ 343,507	~~328,828~~ 337,029
20	Solar PV	~~7,598,989~~ 8,144,627	~~7,550,029~~ 8,093,027	~~7,501,666~~ 8,042,037	~~7,469,194~~ 8,007,968	~~7,405,927~~ 7,941,083	~~7,358,546~~ 7,891,114	~~7,311,489~~ 7,841,481	~~7,279,915~~ 7,808,341	~~7,199,970~~ 7,724,848	~~7,147,369~~ 7,669,709
21	Solar Thermal	~~1,780,838~~ 1,762,261	~~1,780,838~~ 1,762,261	~~1,780,838~~ 1,762,261	~~1,783,858~~ 1,765,243	~~1,780,838~~ 1,762,261	~~1,780,838~~ 1,762,261	~~1,780,838~~ 1,762,261	~~1,783,858~~ 1,765,243	~~1,780,838~~ 1,762,261	~~1,780,838~~ 1,762,261
22	Wind	4,997,701	4,883,296	4,609,823	4,358,250	4,326,117	3,808,664	3,808,664	3,816,232	3,392,738	3,382,295
23	UOG Small Hydro	~~1,467,619~~ 1,473,170	~~1,467,824~~ 1,468,853	~~1,467,546~~ 1,470,226	~~1,470,461~~ 1,471,744	~~1,466,095~~ 1,467,274	~~1,468,461~~ 1,468,960	~~1,466,608~~ 1,465,995	~~1,471,677~~ 1,469,606	~~1,463,931~~ 1,463,822	~~1,468,041~~ 1,467,788
24	UOG Solar	~~320,911~~ 321,281	~~319,242~~ 319,609	~~317,581~~ 317,947	~~316,629~~ 316,293	~~314,286~~ 314,648	~~312,651~~ 313,011	~~311,025~~ 311,384	~~310,093~~ 309,764	~~307,798~~ 308,153	~~306,197~~ 306,551
25	Unbundled RECs	0	0	0	0	0	0	0	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 16 through 25]	~~20,336,980~~ 20,970,511	~~17,922,135~~ 18,548,288	~~17,576,101~~ 18,200,691	~~17,294,939~~ 17,916,598	~~17,173,473~~ 17,790,746	~~16,600,702~~ 17,215,364	~~16,344,285~~ 16,954,629	~~16,292,421~~ 16,899,690	~~15,715,185~~ 16,321,083	~~15,647,181~~ 16,248,304

APPENDIX E

RPS-Eligible Contracts Expiring ~~2015-2025~~

~~January 14,~~ 2016-2026

August 8, 2016

APPENDICES F.1 – F.~~5b~~5

Redacted in Entirety

~~January 14~~August 8, 2016

APPENDIX G

Other Modeling Assumptions Informing Quantitative Calculation

~~January 14~~August 8, 2016

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Other Modeling Assumptions Informing Quantitative Calculation[1]

<table>
<tr><th colspan="2">Assumptions Related to Procurement Quantity Requirement</th></tr>
<tr><td>Compliance Periods</td><td>

As implemented by Decision (“D~~.~~.”) 11-12-020, SB 2 1X requires retail sellers of electricity to meet the following Renewables Portfolio Standard (“RPS”) procurement quantity requirements beginning on January 1, 2011:

An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).
Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
33 percent of bundled retail sales in 2021 and all years thereafter.

~~Under the 40 percent scenario, requirements that are consistent with the following formula: (.33 * 2021 retail sales) + (.37 * 2022 retail sales) + (.37 * 2023 retail sales) + (.40 * 2024 retail sales) and beyond.~~Senate Bill (“SB”) 350 establishes the following new multi-year RPS compliance periods and interim compliance requirements: 40% by the end of 2021-2024; 45% by the end of 2025-2027; and 50% by the end of 2028-2030 and thereafter.

Implementation of SB 350 changes to RPS procurement requirements, including post-2020 compliance period procurement quantity requirements is ongoing in Rulemaking (“R.”) 15-02-020. For its 2016 RPS Plan, Pacific Gas and Electric Company (“PG&E”) assumes continuation of the Portfolio Quantity Requirements (“PQR”) methodology as implemented by D.11-12-020 for compliance periods 2 and 3 (i.e. a “straight-line” trajectory from the quantity for the prior compliance period to the concluding year of the current compliance period to yield the intervening year targets)

</td></tr>
</table>

1 All assumptions in this table reflect an April ~~30, 2015~~, 2016 data vintage (with the exception of the internal sales forecast, which uses a July 2016 vintage) which is consistent with the data vintage of Appendices C1–C4.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Generation	
Non-Qualifying Facility ("QF") Projects *Contracts Executed Post-2002*	• Except for the "OFF/Closely Watched" contract category (see Section 4), all non-QF signed contracts are assumed to deliver at 100% of contract volumes, and deliveries commence within the allowed delay provisions in the contract.
QF Non-Hydro Projects *Contracts Executed Pre-2002*	• Forecast is typically based on an average of the three most recent calendar year deliveries. • Year ~~2015~~2016 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
QF Hydro *Pre-2002 QF, Irrigation District, and Legacy Utility-Owned Assets*	• ~~Forecast~~The forecast for hydro QFs is typically based on historical production, ~~calendar~~ normalized for average year ~~deliveries~~conditions, and ~~regularly updated with~~then adjusted to reflect PG&E's latest internal hydro ~~updates~~outlook. • Projects are forecasted at ~~48~~84% of average water year generation for ~~2015~~2016 (based on PG&E's April ~~30, 2015~~ 2016 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year ~~2015~~2016 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
Non-QF Hydro *Utility Owned Generation ~~(~~("UOG~~)~~") and Irrigation District Water Authority ~~(~~("IDWA~~)~~")*	• Forecasts reflect PG&E's best available projections for hydro conditions. • Projects are forecasted at ~~48~~84% of average water year generation for ~~2015~~2016 (based on PG&E's April ~~30, 2015~~2016 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year ~~2015~~2016 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Future Volumes from Pre-Approved Programs	**~~Feed-in Tariffs~~** **E-SRG, E-PWF (~~AB~~Assembly Bill 1969 FIT)** • All deliveries from executed contracts are assumed at 100% of contract volumes. • Annual energy volumes (for non-operating projects) are modeled based on PG&E's best estimate for project start dates/initial energy delivery date. **~~ReMAT~~** **Renewable Market Adjusting Tariff** • All deliveries from executed contracts are assumed at 100% of contract volumes. • Modeled start date for generic volumes assumed to begin ~~7~~6/1/~~2016~~2017 and ramp up linearly until 1/1/2019, reaching a total of ~~~114~~112 MW. **~~SB1122~~SB 1122 (Bioenergy Feed-in Tariff Program)** • Modeled start date for generic volumes assumed to begin ~~7/~~1/~~2017~~1/2018 and ramp up linearly until ~~7~~3/1/~~2021~~2019, reaching a total of ~~~111~~112 MW. **~~Renewable Auction Mechanism (Remaining Capacity)~~** • ~~For planning purposes PG&E assumed a project start date equal to 12/1/2017.~~ • ~~Technology mix assumed to be 32 MW of as-available peaking.~~ • ~~All deliveries from executed contracts are assumed at 100% of contract volumes.~~ **PV Originally Authorized for PG&E Photovoltaic Program** • Consistent with PG&E's February 26, 2014 Petition for Modification ~~(~~("PFM~~)~~")[2] requesting to terminate the PV Program and modify the Renewable Auction Mechanism ("RAM") Decision process to procure the remaining PV Program volumes using RAM solicitation processes PG&E assumed that the ~~Renewable Auction Mechanism~~RAM accommodates the remaining ~~200~~ 137.5 megawatts ("MW") of PG&E's PV Program

2 Advice Letter 3809-E. http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/RAM/ELEC_3809-E.pdf.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

	volumes. • For planning purposes, PG&E has assumed that a total of ~~209~~137.5 MW will be coming online between ~~2017~~2019 and ~~2018~~2020.[3] • All deliveries from executed contracts are assumed at 100% of contract volumes. ~~All deliveries from executed contracts are assumed at 100% of contract volumes.~~**BioRAM** • [redacted]
Re-contracting	• For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained: 1. PG&E does not yet have contractual commitments for these expiring volumes; 2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life; 3. Contract-renewal bids may not be competitive with offers for new projects received in future solicitations; and 4. Assuming re-contracted volumes obscures PG&E's current real need for additional energy in later years. • Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement of other new resources. • This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E's Annual RPS compliance filing that only shows PG&E's current contractual commitments.
~~**Shortlisted Projects**~~ ~~*From 2014 Solicitation or Bilateral Offer*~~	• ~~No shortlisted projects are included in PG&E's forecast.~~ • ~~Only executed contracts, or generic deliveries from pre-approved procurement programs (i.e., RAM, Feed-in Tariffs, etc.) are included in PG&E's forecast.~~

3 This assumption is based on a modeling vintage of April ~~2015~~2016.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Green Tariff Shared Renewables ~~(~~(“GTSR~~)~~”)	• ~~If the Commission approves PG&E’s pending advice letters to implement GTSR Program, PG&E plans to allocate~~PG&E allocates small amounts of generation from RPS-eligible resources to serve initial GTSR enrollees until new incremental resources procured for the GTSR program are sufficient to meet program needs. • ~~Once the~~When calculating PG&E’s RPS position, GTSR ~~program is underway, PG&~~volumes are removed from PG&E’s RPS-eligible retail sales forecast. • PG&E ~~would also incorporate~~incorporates any GTSR related impacts on its RPS compliance position into ~~future~~ updates to its RNS.
Banking	• PG&E assumes that for the first two compliance periods (2011-2013 and 2014-2016) that (1) Category~~-~~ 3 products that do not exceed applicable portfolio content limits are not deducted from bankable volumes, (2)~~-~~ grandfathered (pre-June 1, 2010) short-term products are bankable, and (3) that banked volumes may be applied in any period onward. ○ PG&E’s accounting is consistent with the direction set forth in ~~Decision~~ D.12-06-038 for compliance periods one and two. • PG&E assumes that beginning in the 2017-2020 compliance period (1) Grandfathered (pre-June 1, 2010) and Category 1 products of any duration are bankable, (2) Category 2 and Category 3 products that fall within the portfolio balance requirements are not deducted from bankable volumes, and (3) that banked volumes may be applied in any period onward.
RPS Sales	• ~~PG&E will continue to assess the value to its customers of sales of surplus procurement. Currently, PG&E’s renewable net short (RNS), future RPS cost projections and assessment of the current REC market does not lead to an expectation of material projected sales of RECs. However, PG&E will consider selling surplus non-bankable RPS volumes and may consider selling surplus bankable volumes if it can still maintain an adequate Bank and if market conditions are favorable. PG&E will update its RNS if it executes any such agreements.~~PG&E has developed a framework to assess whether to hold or sell excess RPS volumes, which will allow PG&E to rebalance its RPS portfolio to better align its RPS position with its RPS need. PG&E is requesting Commission review and approval of this framework as a part of the 2016 RPS Plan. If approved, the proposed framework will be used to determine future sales of bankable RPS volumes. The details of PG&E’s sales framework are discussed in Appendix J.

Appendix G – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Sales	
Bundled Retail Sales *RNS (App. C1~~ and C3~~)*	• Forecasts of retail sales for the first five years of the forecast were generated by PG&E's *Load Forecasting and Research* team in ~~April 2015~~July 2016, and may be updated throughout the year as additional data becomes available. • Forecasts of retail sales beyond the first five years are sourced from the latest ~~LTPP~~Long-Term Procurement Plan standardized planning assumptions, per the May 21, 2014 ~~ALJ~~Administrative Law Judge Ruling in R.11-05-005 regarding the methodology for calculating the renewable net short. Sales forecast used is from the most recently approved bundled sales forecast filed in PG&E's 2014 Conformed Bundled Procurement Plan in Advice Letter 4750-E and approved June 15, 2016. • Monthly recorded sales replace forecasts as ~~2015~~2016 progresses.
Bundled Retail Sales *Alternate RNS* *(App. C2~~ and C4~~)*	• Forecasts of retail sales were generated by PG&E's *Load Forecasting and Research* team in ~~April 2015~~July 2016, and may be updated throughout the year as additional data becomes available. • Monthly recorded sales replace forecasts as ~~2015~~2016 progresses.

APPENDIX H

Responses to Renewable Net Short Questions

~~January 14~~August 8, 2016

Appendix H ~~-~~– Responses to Renewable Net Short Questions

The following presents PG&E's responses to questions set forth in the May~~-~~ 21, 2014 *Administrative Law Judge's Ruling on Renewable Net Short*.

RPS Compliance Risk

1. How do current and historical performance of online resources in your RPS portfolio impact future projections of RPS deliveries and your subsequent RNS?

PG&E considers historical performance of online resources in both of its models. First, it considers this performance in developing the generation forecast in its deterministic model. As discussed in Appendix G, future projections of RPS deliveries in the deterministic model are based on a blended three year average output for QF contracts.

In addition, within its stochastic model, PG&E considers RPS generation variability based on historical performance of each resource type. A probabilistic distribution is built for each resource based on its calculated coefficient of variation. This captures additional RPS generation variability above and beyond the variances that are captured in the deterministic model. Section 6.2.2 of the RPS Plan describes in more detail how historic generation variability from each resource is used as an input to the stochastic model.

2. Do you anticipate any future changes to the current bundled retail sales forecast? If so, describe how the anticipated changes impact the RNS.

PG&E's retail sales are impacted by many factors, including weather, economic growth or recession, technological change, energy efficiency, DA and CCA participation levels, and distributed generation. PG&E's most recent Sales Forecast used in the RPS Plan is an April ~~2015~~2016 updated ~~version of the Alternate Scenario Forecast used in the 2014 Bundled Procurement Plan submitted in October 2014 in Rulemaking 13-12-010~~internal sales forecast. It is important to emphasize that PG&E's Alternative Scenario is a forecast including a number of assumptions regarding events which may or may not occur. PG&E updates the bundled load forecasts annually to reflect any new events and capture actual load changes. As described in more detail in Section 6.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts. Changes in retail sales tend to be variable and persistent, [redacted]~~, particularly over time. However, PG&E's modeling results presented in Section 7 are robust to future changes in sales~~making uncertainty around retail sales one of the largest drivers of RPS outcomes, particularly over time.

3. Do you expect curtailment of RPS projects to impact your projected RPS deliveries and subsequent RNS?

To the extent that RPS projects are economically bid and do not clear the market, or are curtailed for system reliability, PG&E expects that curtailment will impact its RNS. As described in Sections 6.2.3 and 11, the stochastic model evaluates uncertainty associated with RPS generation variability, including assumptions of future levels of RPS curtailment.

4. Are there any significant changes to the success rate of individual RPS projects that impact the RNS?

PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of ~~approximately 99~~100% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, ~~and~~to 87% in PG&E's 2014 RPS Plan~~.~~, and 99% in PG&E's 2015 RPS Plan.[1] This success rate is evolving and highly dependent on the nature of PG&E's portfolio and the general conditions in the renewable energy industry. While PG&E has continued to see a general trend towards higher project success rates, its revised success rate assumption ~~(from 87% to 99%)~~ reflects the recent removal of several projects from PG&E's portfolio due to contract termination and an update to the "Closely Watched" category described in Section 6.

In addition, to model the project failure variability inherent in project development, PG&E adds additional success rate assumptions to it stochastic model, which assume that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. These assumptions are used in order to calculate its stochastically~~-~~-optimized net short (SONS). See the answer to question #5 below for details on these new assumptions.

5. As projects in development move towards their COD, are there any changes to the expected RPS deliveries? If so, how do these changes impact the RNS?

Yes. PG&E may adjust the expected delivery volumes in its deterministic model for RPS projects in development for various reasons. For example, counterparties may make adjustments to their project design, such as decreasing total project capacity, which may lead to changes in expected generation. Counterparties may also experience project delays which impact the delivery date for projects, shifting generation volumes further into the future. In extreme cases, as described in Section 6.1.2, PG&E

[1] PG&E's success rate discussed is more reflective of the success rate of its overall portfolio, and so this percentage does not convey that PG&E has no projects failing. Specifically, since almost all of PG&E's in-development projects are volumes procured through mandated programs with set targets, any projects that fail will be replaced through future solicitation rounds. Therefore the effect on PG&E's portfolio is that the amount of volumes projected has a very high project success rate, given that any failed project will be replaced with a new project, until the volumes come online.

may categorize projects experiencing considerable development challenges as “Closely Watched” and would in those cases reduce the expected delivery volumes from those projects to zero in its deterministic model. Moving a project to the “Closely Watched” category would therefore decrease future delivery volumes and increase the RNS. PG&E has an extensive program for monitoring the development status of RPS-eligible projects, and the deterministic model is updated regularly to reflect any relevant status changes.

In addition, PG&E further reduces its anticipated deliveries from future projects in its stochastic model, as described in more detail in Section 6.2.4. To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]~~.~~[redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] or [redacted] chance of success. This success rate is based on experience, and although PG&E’s current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. ~~Appendices~~Appendix F.~~2a and F.2b~~2 show PG&E’s simulated failure rate and for the period ~~2015~~2016-2030~~ in the 33% RPS and 40% RPS, respectively~~.

SUMMARY:
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Reference Above and Uncertainty it Represents	Deterministic Model	Stochastic Model
Question #2: Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 LTPP for later years.	Distribution based on most recent (~~2015~~2016) PG&E bundled retail sales forecast.
Question #4 and #5: Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	~~Uses~~ [redacted] Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success. ~~Re-contracted projects are assumed to have a~~ [redacted] ~~success rate.~~
Question #1: RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries Hydro QFs, UOG and IDWA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
Question #3: Curtailment[2]	None	~~33% Scenario:~~ [redacted] ~~of RPS requirement~~ ~~40% Scenario:~~ [redacted] ~~of RPS requirement through 2021,~~Curtailment is modeled as increasing ~~to~~ [redacted] between the following data points: [redacted] in 2015 [redacted] in 2020 [redacted] in 2024 ~~and beyond.~~ [redacted] in 2030

2 These modeling assumptions will not necessarily align with the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 11 for more information.

6. What is the appropriate amount of RECs above the PQR to maintain? Please provide a quantitative justification and elaborate on the need for maintaining banked RECs above the PQR.

As described in Sections ~~6~~7 and ~~7~~8, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted]~~ GWh~~[redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted]~~. Under a 40% by 2024 scenario and current market assumptions, PG&E would plan to maintain a minimum Bank level of at least~~ [redacted]~~ GWh~~[redacted]. However, because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a point forecast rather than a static target. Please see Section ~~6~~7 for additional information.

7. What are your strategies for short-term management (10 years forward) and long-term management (10-20 years forward) of RECs above the PQR? Please discuss any plans to use RECs above the PQR for future RPS compliance and/or to sell RECs above the PQR.

As described in Sections 6 and 7, PG&E uses its stochastic model to optimize its procurement. This model currently forecasts Bank levels through [redacted] projecting that PG&E's forecasted Bank size [redacted] GWh by [redacted]. Under this projection, [redacted] Bank will be maintained as VMOP to manage additional risks and uncertainties associated with managing an RPS portfolio.

In the long-term, PG&E will use RECs above the PQR, as needed, to maintain an adequate Bank, as determined by the deterministic and stochastic model or similar means, in order to manage additional risks and uncertainties.

PG&E's optimization strategy includes consideration of sales of surplus procurement. Consistent with the Commission-approved RNS, PG&E's physical net short and cost projections do not include any future projected sales of bankable contracted deliveries. However, PG&E will consider selling surplus ~~non-bankable RPS volumes and may consider selling surplus bankable~~ RPS volumes if it can still maintain adequate Bank and if market conditions are favorable. ~~As PG&E encounters economic opportunities~~PG&E discusses a framework to assess whether to hold or to sell ~~volumes, PG&E will use the stochastic model to help evaluate whether the proposed sale will increase the cumulative non-compliance risk for~~ [redacted]excess RPS volumes in Appendix J.

VMOP

8. Provide VMOP on both a short-term (10 years forward) and long-term (10-20 years forward) basis. This should include a discussion of all risk factors and a quantitative justification for the amount of VMOP.

As discussed in Sections ~~6~~7 and ~~7~~8, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. [redacted], PG&E believes it~~-~~ would be imprudent to use its entire projected Bank toward meeting the ~~33~~50% RPS target~~ or 40% RPS scenario~~, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, the Bank will help to avoid long-term over-procurement above the ~~33~~50% target, and will thus reduce long-term costs of the RPS Program.

9. Please address the cost-effectiveness of different methods for meeting any projected VMOP procurement need, including application of forecast RECs above the PQR.

As discussed in Sections 6 and 7, PG&E's stochastic model optimizes its results to inform its RPS procurement strategy, which includes using a portion of the Bank as VMOP, to achieve the lowest cost possible given a specified risk of non-compliance. The model suggests a specific level of procurement and resulting Bank usage for each year. PG&E then uses these model results as a tool to guide its actual procurement strategy. While the model provides other possible VMOP usage given a specific level of non-compliance risk, these paths would not be minimum cost under the model's assumptions.

~~As a general matter, ~~PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus ~~non-bankable RPS volumes in its portfolio and, in doing so, may seek to sell surplus bankable volumes ~~RPS volumes if it can still maintain an adequate Bank and if market conditions are favorable. PG&E discusses a framework to assess whether to hold or to sell excess RPS volumes in Appendix J.

Cost-Effectiveness

10. Are there cost-effective opportunities to use banked RECs above the PQR for future RPS compliance in lieu of additional RPS procurement to meet the RNS?

As discussed in greater detail in Sections 6, 7, and 8 of this Plan, [redacted]

[redacted]. As long as PG&E can continue to maintain an adequate Bank that does not jeopardize PG&E's ability to manage its non-compliance risk and thus avoid being caught in a "seller's market," where PG&E would face potentially high market prices in order to meet near-term compliance deadlines.

Overall, PG&E can best meet the objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to purchase or sell RPS-eligible products consistent with its RPS Plan on a going-forward basis, continually adapting to these uncertain variables. PG&E will continue to use the stochastic model to help guide decisions around minimum Bank size needed to maintain PG&E's non-compliance risk of [redacted] for the period of [redacted]. PG&E will then procure any needed incremental volumes ratably over time.

11. How does your current RNS fit within the regulatory limitations for PCCs? Are there opportunities to optimize your portfolio by procuring RECs across different PCCs?

PG&E's current RPS portfolio consists of primarily Category 0 and 1 RECs. Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement.

While PG&E seeks opportunities across all product categories to procure the most cost-effective resources to achieve the RPS requirements, the ~~existing~~pre-SB 350 restrictions on banking of excess procurement ~~limit~~have limited PG&E's ability to fully optimize its portfolio. Under the current RPS rules, short-term contracts cannot count towards excess procurement eligible for banking toward a future RPS compliance period. The result is that any entity that has excess procurement during a particular compliance period is effectively restricted from procuring short-term contracts during that compliance period. Only when an entity does not exceed its compliance period target, is it able to count short-term procurement towards meeting its targets.

The changes to the RPS program under SB 350 enable banking of all category 0 and 1 RECs of any duration, beginning in the 2021-2024 compliance period for all entities, or as early as the 2017-2020 compliance period for any entities who elect to comply early with the new SB 350 minimum long-term requirements.[3] In addition, all retired Category 2 and Category 3 RECs that fall within the portfolio balance requirements are eligible to

[3] Although the Commission has not yet implemented this new statutory language by specifying the manner or process by which a retail seller must notify the Commission of its intent to comply early with the minimum long-term requirements, PG&E intends this 2016 RPS Plan to provide such notice if the Commission ultimately determines that the notice should be provided as part of the annual RPS Plan submissions.

be counted towards PG&E's RPS procurement quantity requirement for the compliance period whether the RECs are associated with short-term or long-term contracts.

As PG&E currently maintains a bank in order to help mitigate procurement and load variability~~. Thus~~, the past inability for short-term contracts to contribute to the bank ~~restricts~~has restricted our mitigation strategy. ~~Allowing the unrestricted banking of all RPS products, including those associated with short-term contracts, would enable PG&E to better manage risks and achieve cost-savings for our customers~~The new banking provisions in SB 350 are intended to help address this issue, and should therefore be implemented in a way that provides adequate flexibility to retail sellers in meeting the RPS goals.